OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

MEMORANDUM **November 22, 2004**

TO: Dawson Lasseter, P.E., Chief Engineer, Air Quality Division

THROUGH: David Schutz, P.E., New Source Permits Section
John Howell, E.I., Existing Source Permits Section

THROUGH: Peer Review

FROM: Eric L. Milligan, P.E., Engineering Section

SUBJECT: Evaluation of Construction Permit Application No. **98-172-C (M-17) (PSD)**
Valero Energy Corporation
TPI Petroleum, Inc.
Valero Ardmore Refinery – 200 Long Ton per Day (LTPD) Sulfur Recovery Unit (SRU) with oxygen enrichment, a 200 LTPD Tail Gas Treating Unit (TGTU) & Amine Recovery Unit (ARU), and Modifications to Increase the Crude Oil Processing Rate of the Refinery to 100 Thousand Barrels per Day (MBPD) from 85 MBPD
Ardmore, Carter County
Directions from I-35: east three miles on Highway 142

SECTION I. INTRODUCTION

TPI Petroleum, Incorporated (TPI), a company of Valero, currently operates the Valero Ardmore Refinery located in Carter County, Oklahoma. This construction permit is a modification of a recently issued Prevention of Significant Deterioration (PSD) construction permit that authorized construction and installation of a new 130 LTPD SRU with a 200 LTPD TGTU and ARU in addition to the existing sources at the refinery (Permit No. 98-172-C (M-14) (PSD)). The following changes to the existing refinery operations were proposed in the previously issued construction permit:

1. Installation of a 130 LTPD SRU and associated vessels;
2. Installation of a 40.4 MMBTUH incinerator and a 20.0 MMBTUH hot oil heater;
3. Installation of a 200 LTPD ARU and associated vessels;
4. Installation of a 200 LTPD TGTU and associated vessels;
5. Installation of one cat-feed hydrotreater (CFHT) reactor;
6. Installation of two naphtha hydrotreater (NHT) reactors;
7. Installation of a 1,000 barrel (bbl) regenerated amine storage tank;
8. Installation of a 3,300 bbl molten sulfur storage tank;
9. Installation of new piping and peripheral equipment; and
10. Installation of two electric compressors.

This permit will increase the sulfur recovery rate of the proposed SRU by adding oxygen enrichment to the SRU and addresses the following changes:

1. Refurbishment of the crude oil fractionating tower internals;
2. Refurbishment of the vacuum tower internals;
3. Addition of a high pressure steam condensate receiver;
4. Refurbishment of the kerosene stripper;
5. Refurbishment of the NHT splitter tower internals;
6. Changing the reformer catalyst from R234 to R-264 to prevent underpinning;
7. Refurbishment of the continuous catalyst regeneration unit (CCR) with rerating of the air and chlorination blower;
8. Addition of a chlorosorb system or scrubber for the CCR vent;
9. Refurbishment of the reformer debutanizer internals;
10. Addition of a CFHT Co-Processor and 5 MMBTUH feed pre-heater with low-NO_X burners (LNB);
11. Addition of a distillate heavy-oil desulfurization (DHDS) reactor;
12. Addition of an 11 MMBTUH saturated gas plant reboiler with LNB;
13. Addition of a NHT stripper with a 20 MMBTUH reboiler with LNB;
14. Addition of a 12 MMBTUH NHT reactor inter-heater with LNB;
15. Addition of a heavy diesel stream stripper;
16. Refurbishment of DHDS tower (T-602) and DHDS fractionating tower (T-603) with high efficiency/capacity processing internals;
17. Addition of #3 SWS system;
18. Miscellaneous hydraulic resizing of piping (increase in pipeline sizes);
19. Addition of high efficiency coalescer filter with stainless steel piping and steam tracing for fuel gas distribution system;
20. Addition of three diesel-fired engines for an emergency water curtain/deluge around and over the main HF processing vessels of the alkylation unit;
21. Addition of miscellaneous heat exchangers to include the following:
    a. Five crude oil pre-heat exchangers;
    b. Two new crude charge overhead fin-fan heat exchangers;
    c. A light vacuum gas oil (LVGO) reflux fin-fan heat exchanger;
    d. A LVGO reflux shell/tube heat exchanger;
    e. A heavy diesel steam stripper;
    f. Four NHT pre-heat shell/tube exchangers
    g. Four NHT feed shell/tube exhangers
22. Addition of miscellaneous pumps and other miscellaneous fugitive emission sources associated with the increased crude oil throughput processing rate to include the following:
    a. Two new crude charge pumps;
    b. A crude unit overhead compressor;
    c. Two atmospheric gas oil (AGO) reflux pumps;
    d. Two LVGO reflux pumps;
    e. Two vaccum tower bottoms product pumps;

f. Two heavy naphtha stripper pumps;
g. Two heavy naphtha reflux pumps;
h. Two NHT charge pumps;
i. Two NHT splitter tower reflux pumps;
j. A NHT splitter bottoms pump;
k. Two NHT separator bottoms pumps;
l. A CFHT wash water pump;
m. Two distillate product pumps;
n. Two AGO product pumps;
o. Five pumps unsaturated gas pumps;
p. Replacement of fractionating tower (T-603) kerosene, LSD, and AGO pumps;

The new equipment and units will operate in addition to the refinery's existing source operations and limitations. Permit No. 98-172-C (M-15) (PSD) established throughput limitations for most processes at the facility. All other contemporaneous changes and associated emissions from the refinery were incorporated into or were covered under Permit No. 98-172-C (PSD). Permit No. 98-172-C (PSD) was modified and reissued as Permit No. 98-172-C (M-12) (PSD) and then 98-172-C (M-15) (PSD). Permit No. 98-172-C (M-11) (PSD), which originally authorized this project, was superceded by Permit No. 98-172-C (M-14) (PSD) and will be superceded by this permit.

Some of the throughputs authorized by Permits No. 78-081-O (M-1), 80-060-O (M-1), 80-068-O (M-1), 93-023-O (M-1), and 98-172-C (M-15) (PSD) will be modified by this permit. Permits No. 78-081-O (M-1), 80-060-O (M-1), 80-068-O (M-1), and 93-023-O (M-1) will be superceded by this permit. However, individual limits in Permit No. 98-172-C (M-15) (PSD) that are modified by this permit will be addressed by containing a statement that the throughput limitations of that permit are superseded by the limitations in this permit for each emission unit (EU) or process for which the throughputs are modified. Even after the modifications proposed in this permit, all emissions except for SO_2 emissions will remain below the PSD significance levels. Emissions of SO_2 from the SRU remain the same and the PSD evaluation does not change. The following EU or process throughputs will be modified by this permit:

1. Crude unit throughput will increase from 85 MBPD to 100 MBPD;
2. Vacuum unit throughput will increase from 28 to 34 MBPD;
3. The NHT throughput will increase from 26 MBPD to 33 MBPD;
4. The reformer throughput will increase from 23 to 26 MBPD;
5. The saturated gas plant throughput will increase from 13 to 16 MBPD;
6. The wastewater treatment plant (WWTP) throughput will increase from 506 gpm to 764 gpm.

SECTION II. PROCESS DESCRIPTIONS

The Valero Ardmore Refinery's primary standard industrial classification (SIC) code is 2911. The refinery processes medium and sour crude oils from both the domestic and foreign markets. Major production and processing units include the following: an 85 MBPD crude unit, a 26.2 MBPD vacuum-tower unit, a 12 MBPD asphalt blow-still unit, a 10.4 MBPD polymer modified asphalt unit, a 32 MBPD DHDS unit, a 32 MBPD CFHT unit, a 30 MBPD fluid catalytic cracker unit (FCCU) with two-stage regeneration, a 26 MBPD NHT unit, a 23 MBPD catalytic reformer unit, a 12.5 MBPD Sat-Gas Unit, a 7.5 MBPD alkylation unit, a 7.5 MBPD isomerization unit, a 98 LTPD SRU, and a 26 MMSCFD hydrogen production unit. The majority of raw crude oil is received on-site through utilization of an integrated pipeline system.

To effect operations, the refinery's process heaters, steam boilers, compressors, and generators are capable of producing approximately 1.6 billion BTU/hr of energy transfer. The refinery has approximately 2.4 million barrels of refined product storage capability. Products include conventional and reformulated low sulfur gasoline, diesel fuel, asphalt products, propylene, butane, propane, and sulfur. Refined products are transported via pipeline, railcar, and tank truck.

A. General Function Of Petroleum Refining

Basically, the refining process does four types of operations to crude oil:

1. Separation: Liquid hydrocarbons are distilled by heat separation into gases, gasoline, diesel fuel, fuel oils, and heavier residual material.
2. Conversion:
   i. *Cracking*: This process breaks or cracks large hydrocarbons molecules into smaller ones. This is done by thermal or catalytic cracking.
   ii. *Reforming*: High temperatures and catalysts are used to rearrange the chemical structure of a particular oil stream to improve its quality.
   iii. *Combining*: Chemically combines two or more hydrocarbons such as liquid petroleum gas (LPG) materials to produce high grade gasoline.
3. Purification: Converts contaminants to an easily removable or an acceptable form.
4. Blending: Mixes combinations of hydrocarbon liquids to produce a final product(s).

B. Description of Individual Processes

Crude Unit

The Crude Unit receives a blended crude charge from sweet and sour crude oil feedstock. The crude charge is heated, desalted, heated further, and then fed into the atmospheric tower where separation of light naphtha, heavy naphtha, kerosene, diesel, atmospheric gas oil and reduced crude takes place. The reduced crude from the bottom of the atmospheric tower is pumped through the diesel stripper reboiler and directly to the vacuum tower pre-heater.

After the vacuum tower pre-heater processes the reduced crude, the reduced crude is then processed in the Vacuum Unit to achieve a single stage flash vaporization. A single-stage flash vaporization of the heated reduced crude yields a hot well oil, a light vacuum gas oil, a heavy vacuum gas oil, slop wax, and a vacuum bottoms residual that may be charged to the asphalt blowstill for viscosity improvement or pumped directly to asphalt blending.

DHDS Unit
The DHDS Unit consists of a feed section, reactor section, effluent separator section, recycle gas amine treating section, and a fractionation section. In the feed section, diesel and gas oil are fed to the unit from the Crude Unit main column. From the feed section, the mixed streams are fed to the reactor section. The feed exchanges heat with the feed/reactor effluent exchangers and is charged to the reactor charge heater. From the charge heater, the heated feed passes through a reactor bed where the sulfur and nitrogen are removed. Once the feed leaves the reactor section, it then must be separated in the reactor effluent separator section. The hydrogen gas and hydrocarbon liquid are separated. The hydrogen gas flows to the recycle gas amine treating section where the hydrogen sulfide (H_2S) rich gas stream is cleaned using amine to absorb the sour gas. The hydrocarbon liquid flows to the stripping section of the DHDS unit.

In the stripping section, any LPG with H_2S that is left in the liquid hydrocarbon stream is stripped out with steam. Once the feed has been through the stripping section, it is preheated and fed to the fractionator tower where the kerosene, diesel and gas oil products are fractionated out to meet product specifications.

The equipment to be installed per this construction permit an additional reactor and the supporting peripheral fugitive equipment source, will enable the refinery to comply with the proposed Tier II sulfur standards in 2006 & 2007.

Saturated-Gas Unit
The feedstock to the Sat-Gas Plant is made up of crude oil atmospheric tower overhead liquid product and the platformer debutanizer overhead liquid product. The debutanizer feed is pumped from the debutanizer feed drum to the 40-tray debutanizer. The debutanized light straight run gasoline leaves the bottom of the debutanizer and is sent to the NHT Unit. The condensed overhead stream is pumped to the 30-tray deethanizer. Ethane, H_2S, and lighter components are removed in the overhead stream and sent to the unsaturated gas treating area in the FCCU. The deethanizer bottoms stream that contains propane and butanes is sent to the saturate C_3/C_4 extractor for mercaptan removal and then to the depropanizer. The condensed liquid from the depropanizer overhead accumulator is sent to the propane dryer and then to storage. The depropanizer bottoms stream is sent to the deisobutanizer located at the Alky Unit for separation of iso-butane and normal butane.

Alkylation Unit

The purpose of this unit is to produce high-octane gasoline by catalytically combining light olefins with isobutane in the presence of hydrofluoric (HF) acid. The mixture is maintained under conditions selected to maximize alkylate yield and quality. The alkylate produced is a branched chain paraffin that is generally the highest quality component in the gasoline pool. Besides the high octane, the alkylate produced is clean burning and has excellent antiknock properties. Propane and butane are byproducts.

NHT Unit

The purpose of this unit is to remove the sulfur, nitrogen, and water from the Platformer and Penex (Isomerization) charge stocks. These are contaminants to the Platformer and Penex catalysts. This is accomplished by passing the naphtha feed stocks over hydrotreating catalyst at elevated temperatures in the presence of hydrogen at high pressures. Under these conditions, the sulfur and nitrogen components are converted to H_2S and ammonia (NH_3), which are then easily removed from the liquid effluent by distillation stripping. Removal of the contaminants provides clean charge stocks to the Platformer and Penex units, which increases the operational efficiency of both units.

The equipment to be installed per this construction permit, two additional reactors and the supporting peripheral fugitive equipment sources, will reduce the space velocity by a factor of four and thus enable more intimate catalyst contact in the presence of hydrogen. This will enable more efficient removal of sulfur from the platformer feedstock.

Platformer Unit

The purpose of this unit is to upgrade low octane naphtha to higher-octane gasoline blending stock. The naphtha is a specific boiling range cut from the Crude Unit. The naphtha is upgraded by using platinum catalyst to promote specific groups of chemical reactions. These reactions promote aromatic formation, which gives the boost in octane. A byproduct from the reactions is hydrogen. The hydrogen is processed to the NHT or CFHT units to aid in hydrotreating of the feedstock(s). The reactions produce light hydrocarbon gases, which are sent to the sat-gas unit.

The CCR section of the Platformer Unit allows the reaction section to operate efficiently while maintaining throughput year round. The CCR continuously regenerates a circulating stream of catalyst from the reactors. During normal operations in the reaction section, catalyst activation is lowered due to feedstock contaminants and coke buildup. The regeneration section continuously burns off the coke deposit and restores activity, selectivity and stability to essentially fresh catalyst levels.

Isomerization Unit

The purpose of this unit is to increase the octane of light naphtha. The octane is increased by catalytically rearranging straight chain hydrocarbons to branched hydrocarbons. This process is called "isomerization." The bulk of the products from the unit are the isomerates (C_5's and C_6's), which are added to the refinery's gasoline blending pool. The advantage of using isomerate is good motor octane, benzene saturation, and aromatic reduction. There will be a small yield of light hydrocarbons, which are added to the refinery fuel gas system.

CFHT

Hydrotreating is a process to remove impurities present in hydrocarbons and/or catalytically stabilize petroleum products by reacting them with hydrogen. The CFHT has two primary functions: 1) improve the quality of the feed to the FCCU by removing impurities (metals, sulfur, and nitrogen), and 2) increasing the hydrogen content by saturating the aromatics in the gas oils and light cycle oil feedstocks.

Feed to the CFHT enters the unit from several sources: high sulfur diesel from Tank T-1081; light cycle oil from the FCCU; gas oil from the Crude Unit; either vacuum or atmospheric residue from the Crude Unit; and hydrogen from the Hydrogen Unit. The combined liquid feed is filtered and then heated in a series of exchangers before entering the feed surge drum. Liquid feed from the surge drum is pumped to the reaction section of the unit through the multistage charge pump. Hydrogen feed is compressed to the unit operating pressure by two reciprocating compressors. The fresh hydrogen feed along with recycled hydrogen from a steam turbine driven centrifugal compressor combines with the liquid feed in the reaction section of the unit.

Combined feed to the unit is heated in the reactor charge heater and then enters the first of three reactors in series. The reactors each contain a different type of catalyst with a very specific, but complementary role. The primary role of the catalyst in the first two reactors is to remove metals contained in the feed such as nickel and vanadium. The catalyst in the third reactor is primarily designed to convert sulfur and nitrogen species into a form in which they can be removed. The effluent from the reactors then enters a series of separators.

There are four separators in the CFHT: the hot high pressure separator, the hot flash drum, the cold high pressure separator, and the cold flash drum. The primary function of these vessels is to separate the oil from the hydrogen-rich gas in the reactor effluent. Each vessel is operated at different conditions (temperature and pressure) to allow certain components in the reactor effluent to vaporize. Hydrogen recovered in the cold high-pressure separator is routed to the recycle gas amine treater. Light ends, such as methane and ethane, are sent to the refinery sour fuel gas system. Water recovered is sent to a sour water stripper. All of the remaining oil is then combined and sent to the fractionation section of the unit.

Hydrogen recovered from the reactor effluent contains H_2S. The unit is designed to have 0.5-1.0% H_2S in the recycle gas. To control the H_2S at the desired level, a portion of the recycle gas is amine treated. Recycle gas enters the bottom of the amine absorber and is contacted by a counter-current flow of amine. The H_2S is absorbed by the amine and sweet hydrogen exits the top of the absorber. Amine exits the bottom of the absorber and is regenerated in the ARU.

The oil from the separators is routed to the fractionation section of the unit. The oil is heated in the fractionator charge heater and then enters the fractionator. The fractionator is a trayed tower. The fractionator separates the oil into three streams: overhead naphtha product, diesel product, and FCCU feed. The diesel product is stripped of light ends and H_2S in the distillate stripper before being sent to storage.

The equipment to be installed per this construction permit, an additional reactor, co-processor reactor, and the supporting peripheral fugitive equipment source, will enable more efficient sweetening of the FCCU feedstock and is a step toward complying with the proposed Tier II sulfur standards in 2006 & 2007.

FCCU

The main purpose of the FCCU is to break up heavy hydrocarbons into a mixture of lighter hydrocarbons and then separate the mixture. The major divisions of the plant are the FCCU charge system, the reactor-regenerators, the main (fractionator) column, and the gas concentration unit.

In the FCC Charge System, the feed is collected in a common feedstock surge drum and heated before it is sent to the FCCU. The feedstock comes from four sources: residuum from the vacuum tower, treated gas oil from storage, gas oil from the crude/DHDS unit, and hot gas oil from the CFHT Unit. The hot and cold charge streams are mixed in the charge drum to reach a desired temperature. The outlet stream from this drum combines with the residuum stream and is pumped through the charge heater where, if necessary, the feed is heated. Finally, the feed is sent to the FCCU reactor to effect the desired cracking reactions.

The catalytic cracking for the process is achieved by processing the superheated feedstock with a cracking promoting catalyst. A byproduct, coke, is produced during the cracking reactions. As a result, the catalyst is covered with coke that must be burned off the catalyst. This is achieved in the FCCU No. 1 and No. 2 regenerators. This burning process results in temperatures normally above 1,300°F. The hot catalyst is recirculated through the system to mix with more feed to control the reactor temperature.

The cracked gas oil must be separated into useable products, namely slurry or #6 fuel oil, light cycle oil (LCO) or diesel fuel, FCCU gasoline or blend stock for motor gasoline and light liquefied petroleum gases (LPG) including olefins.

Sour Water Strippers

The purpose of the sour water strippers is to remove H_2S and ammonia from the total sour water inlet stream. The H_2S and ammonia are stripped from the sour water feed as the water travels down the column. Rising steam strips out the H_2S and ammonia gases. These gases are routed to the SRU/SCOT Unit to convert the H_2S gas stream to sulfur and to destroy the ammonia gas in the thermal section of the SRU.

ARU

Methyldiethanolamine (MDEA) is used to recover carbon dioxide (CO_2) and H_2S to form a weak and unstable salt. These processes take place in the fuel gas absorber and amine contactors. Once this weak and unstable amine salt solution is formed, the reaction must be reversed to clean up or regenerate the amine solution. This reaction takes place in the ARU. The new amine unit will increase the CO_2 and H_2S removal efficiency of the refinery.

The MDEA solution is fed to the tower from the MDEA flash drum. As the solution travels down the tower, the acid gases are stripped as the salt solution is broken down by heat, which is supplied by two steam reboilers at the base of the tower. The lean regenerated MDEA is then pumped back to the lean MDEA surge drum where the low- and high-pressure MDEA charge pumps charge the regenerated amine solution back to the fuel gas absorber and amine contactors.

SRU / SCOT Process

The SRU converts the H_2S stream from the ARU to liquid elemental sulfur to be loaded out by railcar or truck. This process takes place in two general sections: 1) H_2S is converted to sulfur at high temperatures without the aid of catalytic conversion; and 2) sulfur is formed at much lower temperatures with the aid of catalytic conversion.

In section one, high thermal temperatures are maintained by using liquid oxygen, which also aids in the destruction of ammonia contained in the sour water gases which are destroyed in the thermal section of the SRU. In section two, unconverted sulfur is processed through two or more successive catalytic stages. Each stage consists of process gas reheating, sulfur conversion over an activated alumina catalyst and then cooling to condense and recover the sulfur formed.

The SCOT Unit operation is much the same as the MDEA Unit operation. Unprocessed tail gas from the SRU is heated and mixed with a hydrogen rich reducing gas stream. This heated tail gas stream passes through a catalytic reactor where the sulfur compounds are reconverted back to H_2S. Once the tail gases are converted back into a H_2S gas stream, these gases are routed to a quench system where the gases are cooled and the condensed water from the reactor product is routed to the sour water system. The cooled reactor effluent is then fed to an absorber/stripper section where the acid gas comes in contact with an amine solution and is absorbed, regenerated, and reprocessed by the SRU.

The new SRU and the TGTU will increase the refinery's sulfur recovery capacity. The new units will be able to handle the additional H_2S generated in the new reactors for the NHT and the CFHT.

WWTP

The WWTP is for the purpose of treating refinery wastewater from the various units and tank farm to comply with specific discharge characteristics specified by the refinery National Pollution Discharge Elimination System (NPDES/OKPDES) permit. The system is comprised of an oily water sewer collection system from the various units and the tank farm, a lift station, two above ground oil water separation tanks, two aggressive bio-reaction tanks, 16 aerated lagoons and two clarifier lagoons. Flow through the system from beginning to discharge is as stated above. The system treats approximately 600,000 gallons of wastewater daily.

Product Movement Tank Farm

The purpose of the tank farm and product movement area is to receive, hold, blend, and ship hydrocarbon products in a safe and efficient manner. The major product groups include crude, intermediate feedstocks, LPG, gasolines, distillates, heavy fuel oil, and asphalts. Distillate and gasoline products are shipped via three outlets. These products are also loaded onto trucks at the truck dock. Various LPG's are loaded and unloaded by truck and rail. Asphalt and heavy fuel oil are primarily shipped by truck, but rail connections can also be used.

SECTION III. AFFECTED EQUIPMENT - EMISSION UNIT (EU) GROUPS

EUG 1 Tank T-1008

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1008	P-1	Cone	LCO/Slurry	2,115	1975

Permit No. 74-171-O

EUG 6 Tank T-1118

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1118	P-6	Cone	Asphalt	35,000	1970

Grandfathered

EUG 8 Tank T-1135

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1135	P-8	Cone	Gasoline Blending	362	1968

Grandfathered

EUG 10 Tank T-1078 – To be Dismantled

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1078	P-10	Cone	Heavy Naphtha	10,545	1968

Grandfathered

EUG 11 Tank T-1079 – To be Dismantled

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1079	P-11	Cone	Heavy Naphtha	9,948	1968

Grandfathered

EUG 13 Tank T-1081

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1081	P-13	Cone	Diesel / Premium Diesel	79,917	1974

Permit No. 74-171-O

EUG 14 Tank T-1082

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1082	P-14	External Floating	Crude Oil	124,714	1974

Permit No. 74-171-O

EUG 15 Tank T-1083

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1083	P-15	External Floating	Crude Oil	124,714	1974

Permit No. 74-171-O

EUG 16 Tank T-1084

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1084	P-16	External Floating	Crude Oil	124,714	1978

Permit No. 78-081-O (M-1)

EUG 17 Tank T-1085

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1085	P-17	Cone	Slurry / #6 Fuel Oil	55,319	1953

Grandfathered

EUG 19 Tank T-1102 & T-1151

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1102	P-19	Cone	Asphalt	77,000	1975
T-1151	P-189	Cone	Asphalt	176,395	1953

T-1102 - Permit No. 74-171-O; T-1151 - Grandfathered

EUG 20 Tanks T-1111 & T-1112 – To be Dismantled

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1111	P-20	Cone	Asphalt / Fuel Oil	55,012	1954
T-1112	P-21	Cone	Asphalt / Fuel Oil	10,100	1954

Grandfathered

EUG 21 Tank T-1113

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1113	P-22	Cone	Asphalt	131,283	1980

Permit No. 74-171-O

EUG 24 Tank T-1121

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1121	P-27	Cone	Diesel / Jet Fuel	40,526	1968

Grandfathered

EUG 26 Tank T-1123

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1123	P-29	External Floating	Gasoline	59,119	<1968

Grandfathered

EUG 27 Tank T-1124

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1124	P-30	External Floating	Gasoline	111,714	<1972

Grandfathered

EUG 28 Tank T-1125

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1125	P-31	External Floating	Gasoline	124,405	1974

Permit No. 74-171-O

EUG 29 Tank T-1126

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1126	P-32	External Floating	Gasoline	124,405	1974

Permit No. 74-171-O

EUG 30 Tank T-1127

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1127	P-33	Cone	Diesel / Jet Fuel	80,579	1974

Permit No. 74-171-O

EUG 31 Tank T-1128

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1128	P-34	Cone	Diesel / Jet Fuel	80,636	1974

Permit No. 74-171-O

EUG 32 Tank T-1129

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1129	P-35	Cone	Diesel / Jet Fuel	2,113	1975

Permit No. 74-171-O

EUG 34 Tank T-1131

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1131	P-37	External Floating	Gasoline	125,095	1979

Permit No. 80-060-O (M-1)

EUG 35 Tank T-1132

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1132	P-38	External Floating	Reformate	80,143	1979

Permit No. 80-068-O (M-1)

EUG 40 Tank V-818

EU	Point	Roof Type	Contents	Barrels	Const. Date
V-818	P-43	Cone	Slop Oil	300	<1968

Grandfathered

EUG 41 Oil-Water Separators V-8801 & V-8802

EU	Point	Roof Type	Contents	Barrels	Const. Date
V-8801	P-44	External Floating	Oil / Water	17,200	1993
V-8802	P-45	External Floating	Oil / Water	17,200	1993

Permit No. 93-023-O (M-1)

EUG 48 Sour Water Stripper Tank T-1152

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1152	P-55	Cone	Sour Water	10,424	1999

Grandfathered

EUG 49 Sour Water Stripper Tank T-84001

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-84001	P-184	Cone	Sour Water	18,905	2004-5

New

EUG 107 Process Heater

EU	Point		MMBTUH	Const. Date
H-601	P-108	Process Heater	50.4	1974

Permit No. 74-171-O

EUG 109 Process Heater

EU	Point		MMBTUH	Const. Date
H-901	P-110	Process Heater	51.9	<1968

Grandfathered

EUG 117 Process Heater

EU	Point		MMBTUH	Const. Date
H-103	P-118	Process Heater	102.6	1974

Permit No. 74-171-O

EUG 119 Process Heater

EU	Point		MMBTUH	Const. Date
H-301	P-120	Process Heater	22.5	1974

Permit No. 74-171-O

EUG 125 Boiler

EU	Point		MMBTUH	Const. Date
B-801	P-126	Boiler	72.5	1974

Permit No. 74-171-O

EUG 146 Platformer Catalyst Regeneration Vent

EU	Point	Description	Const. Date
CCR	P-150	Platformer Catalyst Regeneration Combustion Vent	1980

Permit No. 98-172-C (M-15) (PSD)

EUG 169 Tank T-1155

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1155	P-169	External Floating	Heavy Naphtha	164,000	2003-4

Permit No. 98-172-C (M-15) (PSD)

EUG 170 SRU Incinerator

EU	Point	Description	MMBTUH	Const. Date
SBH-001	P-170	SRU Incinerator	40.4	2004

New

EUG 171 Hot Oil Heater

EU	Point	Description	MMBTUH	Const. Date
SBH-002	P-171	Hot Oil Heater	20.0	2004

New

EUG 172 Regenerated Amine Storage Tank TK-AB001

EU	Point	Roof Type	Contents	Barrels	Const. Date
TK-AB001	P-172	Cone	Amine	895	2004

New

EUG 173 Liquid Sulfur Storage Tank TK-SB001

EU	Point	Roof Type	Contents	Barrels	Const. Date
TK-SB001	P-171	Cone	Sulfur	3,300	2004

New

EUG 174 Molten Sulfur Railcar Loading Rack

EU	Point	Loading Rack	Loading Arm
LR-SB001	P-171	1	1
			2
			3

New

EUG 175 WWTP Incinerator

EU	Point	Description	MMBTUH	Const. Date
HI-8801	P-176	WWTP Incinerator	15.0	2004

Permit No. 93-023-O (M-1)

EUG 180 Co-Processor Heater

EU	Point	Description	MMBTUH	Const. Date
H-6503	P-180	Co-Processor Heater	5.0	2004

New

EUG 181 Sat- Gas Debutanizer Reboiler

EU	Point	Description	MMBTUH	Const. Date
H-302	P-181	Sat-Gas Debutanizer Reboiler	11.0	2004

New

EUG 182 NHT Hydrocarbon Stripper Reboiler

EU	Point	Description	MMBTUH	Const. Date
H-402C	P-182	NHT Stripper Reboiler	20.0	2004

New

EUG 183 NHT Reactor Inter-Heater

EU	Point	Description	MMBTUH	Const. Date
H-408	P-183	NHT Reactor Inter-Heater	12.0	2004

New

EUG 184 Emergency Water-Curtain Pumps Diesel Engines

EU	Point	Make/Model	HP	Const. Date
EWCP-1	P-185	Caterpillar 3412	660	2004
EWCP-2	P-186	Caterpillar 3412	660	2004
EWCP-3	P-187	Caterpillar 3412	660	2004

New

EUG 200 Crude Unit Fugitive Sources

EU	Point	Number Items	Type of Equipment
Area 100	F-100	2,478	Valves
		4,249	Flanges
		72	Other
		3	Compressors
		29	Pump Seals

EUG 204 Unsaturated Gas Plant Fugitive VOC Emissions

EU	Point	Number Items	Type of Equipment
Area 200	F-104	617	Valves
		969	Flanges
		8	Other

EUG 206 Sat. Gas Plant Fugitive Sources

EU	Point	Number Items	Type of Equipment
Area 300	F-106	857	Valves
		1,457	Flanges
		30	Other
		7	Pump Seals

EUG 207 Reformer "Platformer" Fugitive Sources

EU	Point	Number Items	Type of Equipment
Area 400	F-107	866	Valves
		1,472	Flanges
		20	Other
		3	Compressors
		5	Pump Seals

EUG 210 CFHT Unit Fugitive VOC Emissions

EU	Point	Number Items	Type of Equipment
Area 650	F-110	1,544	Valves
		2,597	Flanges
		57	Other
		3	Compressor
		4	Pump Seals

EUG 214 WWTP Fugitive Sources

EU	Point	Number Items	Type of Equipment
ASU	F-114	233	Valves
		416	Flanges
		4	Pump Seals
		3	Drains

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EUG 215 LPG Loading Operations Fugitive VOC Emissions

EU	Point	Number Items	Type of Equipment
LPG	F-115	225	Valves
		383	Flanges
		6	Other
		2	Pump Seals
		2	Loading Arms

EUG 217 SWS No. 3 Fugitive Sources

EU	Point	Number Items	Type of Equipment
Area 840	F-840	127	Valves
		165	Flanges
		6	Pump Seals

EUG 220 NHT Fugitive VOC Emissions

EU	Point	Number Items	Type of Equipment
Area 400	F-107	1,510	Valves
		2,544	Flanges
		63	Other
		4	Compressor
		18	Pump Seals

EUG 223 Asphalt and No. 6 Fuel Oil Railcar Loading

EU	Point	Loading Bays	Loading Arm
AsRail	F-124	2	1
			2
			3
			4

EUG 224 Asphalt and No. 6 Fuel Oil Truck Loading

EU	Point	Loading Bays	Loading Arm
AsTruk	F-125	4	1
			2
			3
			4
			5
			6

EUG 230 Amine Regenerator / SRU Unit #2 Wastewater Processing

EU	Point	Number Items	Type of Equipment
WWAB-001	F-AB001	12	P-Trap
		2	Junction Boxes

EUG 231 SCOT Unit #2 Wastewater Processing

EU	Point	Number Items	Type of Equipment
WWSB-001	F-SB001	9	P-Trap
		1	Junction Box

EUG 530 SCOT Unit #2 Fugitive Sources

EU	Point	Number Items	Type of Equipment
Area 530	F-530	282	Valves
		499	Flanges
		4	Other
		6	Pump Seals

EUG 560 Amine Regeneration Unit #2 Fugitive Sources

EU	Point	Number Items	Type of Equipment
Area 560	F-560	314	Valves
		630	Flanges
		8	Other
		6	Pump Seals

EUG 570 SRU Tail Gas Treating Unit #2 Fugitive Sources

EU	Point	Number Items	Type of Equipment
Area 570	F-570	252	Valves
		560	Flanges
		3	Other
		7	Pump Seals

SECTION IV. EMISSIONS

The table below provides a list of active permits affected by this permit. This permit will supercede any conditions of the previous permits that affect the EUs incorporated into this permit.

List of Affected Air Quality Permits and Determinations

74-171-C	80-060-O (M-1)*	93-023-O (M-1)*
78-081-O (M-1)*	80-068-O (M-1)*	98-172-C (M-15) (PSD)

* - This permit will incorporate all of the EUs of these affected permits and these permits will become null and void upon commencement of construction.

Associated VOC Emissions from the Asphalt and Gas-Oil/Slurry/#6 Fuel Oil Railcar & Truck Loading

The table below shows the associated VOC emission increases from asphalt and gas-oil/slurry/#6 fuel oil railcar and truck loading due to an increase in throughput (barrels per year (BPY)) of the Crude Unit from 85 MBPD to 100 MBPD based on AP-42 (1/95), Section 5.2 and the listed throughputs.

	85 MBPD		**100 MBPD**		**Change in**
	Throughput	**Emissions**	**Throughput**	**Emissions**	**Emissions**
Loading	**BPY**	**TPY**	**BPY**	**TPY**	**TPY**
Railcar	4,015,000	14.114	4,745,000	16.681	2.567
Tank Truck	162,425	0.004	191,625	0.004	0.000
Total					2.567

Emissions from the Process Heaters H-601, H-901, H-103, & H-301, & Boiler B-801

The table below shows the estimated potential emissions for the process heaters and boiler and assumes 100% conversion of H_2S in the fuel gas to SO_2. These EU were included in the modeling conducted for Permit No. 98-172-C (M-15) (PSD). Since there were included in a previous PSD permit, no associated emission increases were calculated for these heaters. However, these EU will be incorporated into this permit.

	NO_X		**CO**		**PM_{10}**		**SO_2**		**VOC**	
Heaters	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
H-601	5.7	25.1	4.8	21.1	0.4	1.9	2.0	8.6	0.3	1.4
H-901	5.9	25.8	4.9	21.6	0.5	2.0	2.0	8.8	0.3	1.4
H-103	10.1	44.1	8.5	37.0	0.8	3.4	3.5	15.1	0.6	2.4
H-301	2.1	9.3	1.8	7.8	0.2	0.7	0.7	3.2	0.1	0.5
Boiler										
B-801	7.1	31.1	6.0	26.2	0.5	2.4	2.4	10.7	0.4	1.7

Emissions are based on the following heat input ratings HHV (MMBTUH) and emission factors:

H-601 - 50.4, H-901 - 51.9, H-103 – 102.6, H-301 - 22.5, B-801 – 72.5;

NO_X, CO, PM_{10}, & VOC - AP-42, Section 1.4 (7/98);

SO_2 - A fuel-gas H_2S concentration of 159 ppmv and a HHV of 800 BTU/SCF.

Associated VOC Emissions from the Storage Tanks

The table below shows the associated VOC emission increases from the storage tanks due to an increase in throughput (barrels per year (BPY)) of the Crude Unit from 85 MBPD to 100 MBPD based on TANKS4.09b and the listed throughputs.

	85 MBPD		100 MBPD		Change in
	Throughput	Emissions	Throughput	Emissions	Emissions
Tank	BPY	TPY	BPY	TPY	TPY
T-818	60,209	0.007	70,832	0.008	0.001
T-1008	1,932,521	0.007	2,275,243	0.008	0.001
T-1018	----	----	9,490,000	0.518	0.518
T-1081	----	----	1,822,982	0.859	0.859
T-1082	10,341,667	3.674	12,166,667	3.916	0.242
T-1083	10,341,667	3.749	12,166,667	3.972	0.223
T-1084	10,341,667	3.125	12,166,667	3.371	0.246
T-1085	381,246	0.007	447,964	0.008	0.001
T-1102	589,981	0.798	668,240	0.931	0.133
T-1111	434,363	0.587	506,757	0.685	0.098
T-1113	1,029,041	1.392	1,200,548	1.624	0.232
T-1118	628,864	0.850	733,674	0.992	0.142
T-1121	1,012,461	0.537	1,190,974	0.629	0.092
T-1123	2,325,262	9.126	2,735,640	9.141	0.015
T-1124	4,182,670	9.636	4,920,856	9.661	0.025
T-1125	4,668,158	11.928	7,500,000	12.000	0.072
T-1126	4,668,158	11.748	7,500,000	12.000	0.252
T-1127	1,999,923	1.064	3,300,000	1.560	0.496
T-1128	1,999,923	1.064	3,300,000	1.560	0.496
T-1129	52,081	0.027	61,264	0.032	0.005
T-1132	8,395,000	4.782	9,490,000	4.848	0.066
T-1135	----	----	4,424	0.241	0.241
T-1141	3,042,112	1.635	3,578,477	1.910	0.275
T-1142	2,033,394	1.081	2,391,914	1.265	0.184
T-1151	1,200,000	2.194	1,893,114	2.560	0.366
T-1155	9,490,000	2.653	12,045,000	3.129	0.476
T-84001	----	----	2,502,857	1.350	1.350
T-8801	3,166,114	3.335	4,780,457	3.668	0.333
T-8802	3,166,114	3.335	4,780,457	3.668	0.333
T-100149	1,200,000	1.623	1,400,000	1.768	0.145
T-100150	2,400,000	1.994	2,800,000	2.084	0.090
T-210001	2,400,000	1.642	2,800,000	1.915	0.273
T-210003	1,200,000	1.190	13,898,970	1.326	0.136
T-210004	1,800,000	2.031	2,100,000	2.236	0.205
T-210005	1,800,000	2.031	2,100,000	2.236	0.205
T-210006	1,200,000	2.072	1,400,000	2.209	0.137
T-210007	1,200,000	2.072	1,400,000	2.209	0.137
T-210008	1,200,000	2.304	1,400,000	2.441	0.137
TOTALS		**95.300**		**104.538**	**9.238**

Emissions from the Reformer CCR

The table below details the emissions for the Reformer CCR as authorized by Permit No. 98-172-C (M-15) PSD, emissions after the modification, and the change in emissions.

	NO_X		CO		PM_{10}		SO_2		VOC	
	lb/hr	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
Pre[1]	0.8	3.7	0.1	0.5	0.4	1.7	0.5	2.0	0.03	0.1
Post[2]	1.2	5.2	0.2	0.8	0.6	2.5	0.7	2.9	0.05	0.2
Change	**0.4**	**1.5**	**0.1**	**0.3**	**0.2**	**0.8**	**0.2**	**0.9**	**0.02**	**0.1**

[1] Emissions are based on the emission factors below and a coke-burning rate of 49 lbs/hr, which is equivalent to a maximum catalyst recirculation rate of 700 lb/hr and a coke generation rate of 7% of the catalyst weight, with a coke maximum sulfur content of 0.5% by weight.

[2] Emissions are based on a coke-burning rate of 70 lbs/hr, which is equivalent to a maximum catalyst recirculation rate of 1,000 lb/hr and a coke generation rate of 7% of the catalyst weight, with a coke maximum sulfur content of 0.5% by weight. Coke combustion emissions were based on AP-42 (1/95), Section 1.1, for sub-bituminous coal combustion. PM_{10} emissions also include a recovery factor for the catalyst of 99.99%.

Coke combustion emissions were based on the factors from AP-42 (1/95), Section 1.1, for sub-bituminous coal combustion since there are no factors for coke combustion. PM_{10} emissions also include a recovery factor for the catalyst of 99.99%.

NO_X - 34 lb/ton of coke combusted (Pulverized coal fired, wet bottom);
CO - 5 lb/ton of coke combusted (Spreader Stoker);
PM_{10} - 13.2 lb/ton of coke combusted (Spreader Stoker); 0.07 & 0.10 lb/hr catalyst;
SO_2 - 38 x (Sulfur Content) lb/ton of coke combusted (Spreader Stoker);
VOC - 1.3 lb/ton of coke combusted (Underfeed Stoker).

Ethylene dichloride ($C_2H_4Cl_2$) or perchloroethylene ($Cl_2C:CCl_2$) is injected into the reformer and then discharged as hydrogen chloride (HCl). Usage of ethylene dichloride was limited to approximately 8.87 TPY in Permit No. 98-172-C (M-15). This permit will increase usage, establish a chlorine usage limit rather than a limit on the type of material providing the chlorine, and will require the facility to comply with the MACT (97% control of HCl from the CCR or 10 ppmv HCl @ 3% O_2). Ethylene dichloride or perchloroethylene is almost completely destroyed by reaction with the catalyst and air. Estimated material usage is based on 0.0106 lb of perchloroethylene per barrel with the CCR running at 26 MBPD. Potential HCl emissions are based on 100% of the chloride being converted to HCl and being emitted from the CCR. Emissions of HCl from the CCR after control are estimated using the required control of 97%. The controls for HCl will also help reduce PM_{10} emissions by approximately 95%.

	Uncontrolled		Controlled	
	lb/hr	**TPY**	**lb/hr**	**TPY**
HCl Emissions	10.1	44.1	0.3	1.3

Emissions from the SRU Incinerator SBH-001

The new SRU will vent to the incinerator along with the displaced vapors from the railcar loading operations and the storage tank. Emission estimates assume 100% conversion of H_2S to SO_2. The table below shows the emission estimates for the SRU Incinerator.

NO_X		CO		PM_{10}		SO_2		VOC	
lb/hr	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
4.0	17.4	1.1	4.6	0.3	1.3	26.2	114.7	0.2	1.0

Emissions from the incinerator are based on the following:

NO_X - For emissions from combustion of the auxiliary fuel, emissions were based on a heat rating of 27.7 MMBTUH, a heat content of 867 BTU/SCF, and the emission factor from AP-42, Section 1.4 (7/98); for emissions from combustion of the waste gas, emissions were based on a flow rate of 552,396 SCFH of waste gas, a heat content of 23 BTU/SCF, and the emission factor from AP-42, Section 1.4 (7/98);

CO - For emissions from combustion of the auxiliary fuel, emissions were based on a heat rating of 27.7 MMBTUH, a heat content of 867 BTU/SCF, and the emission factor from AP-42, Section 1.4 (7/98); for emissions from combustion of the waste gas, emissions were based on a flow rate of 552,396 SCFH of waste gas, a heat content of 23 BTU/SCF, and the emission factor from AP-42, Section 1.4 (7/98);

PM_{10} - For emissions from combustion of the auxiliary fuel, emissions were based on a heat rating of 27.7 MMBTUH, a heat content of 867 BTU/SCF, and the emission factor from AP-42, Section 1.4 (7/98); for emissions from combustion of the waste gas, emissions were based on a flow rate of 552,396 SCFH of waste gas, a heat content of 23 BTU/SCF, and the emission factor from AP-42, Section 1.4 (7/98);

SO_2 - Based on the NSPS, Subpart J, SO_2 emission limit of 250 ppmdv and a flow rate of 630,000 DSCFH @ 0% O_2;

VOC - For emissions from combustion of the auxiliary fuel, emissions were based on a heat rating of 27.7 MMBTUH, a heat content of 867 BTU/SCF, and the emission factor from AP-42, Section 1.4 (7/98); for emissions from combustion of the waste gas, emissions were based on a flow rate of 552,396 SCFH of waste gas, a heat content of 23 BTU/SCF, and the emission factor from AP-42, Section 1.4 (7/98).

Emissions from the Regenerated Amine Storage Tank TK-AB001

The table below shows the estimated emissions from the regenerated amine storage tank. Emissions are based on TANKS4.0, a throughput of 12,463,046 BPY, and a H_2S concentration of 0.1% by weight.

	VOC		H_2S	
	lb/hr	**TPY**	**lb/hr**	**TPY**
Emissions	<0.1	<0.1	0.1	0.5

Emissions from the Hot Oil Heater SBH-002

The table below shows the estimated emissions for heater SBH-002 and assumes 100% conversion of H_2S in the fuel gas to SO_2.

NO_X		CO		PM_{10}		SO_2		VOC	
lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
1.0	4.3	1.7	7.2	0.2	0.7	0.6	2.7	0.1	0.5

Emissions from the heater are based on a heat rating of 20 MMBTUH, continuous operation, and the emission factors shown below:

NO_X - AP-42, Section 1.4 (7/98), LNB factor;
CO - AP-42, Section 1.4 (7/98);
PM_{10} - AP-42, Section 1.4 (7/98);
SO_2 - A fuel-gas H_2S concentration of 159 ppmv;
VOC - AP-42, Section 1.4 (7/98).

Emissions from the Liquid Sulfur Storage Tank TK-SB001

The table below shows the estimated emissions from the liquid sulfur storage tank. Emissions are based on a H_2S concentration of 8,000 ppmv (based on historical analyses of sulfur pit sweep vapors ~2,000 ppmv plus a safety factor of four), the run-down rate of 12,100 lb/hr of molten sulfur (130 LTD), and the density of molten sulfur (124.8 lb/SCF). These emissions are vented to the SRU incinerator and are incorporated into that limit as SO_2.

	H_2S	
	lb/hr	TPY
Emissions	0.1	0.3

Emissions from the Molten Sulfur Railcar Loading Rack LR-SB001

The table below shows the estimated emissions from the molten sulfur railcar loading rack. Emissions are based on a H_2S concentration of 8,000 ppmv (based on historical analyses of sulfur pit sweep vapors ~2,000 ppmv plus a safety factor of four), a loading rate of 100,000 lb/hr of molten sulfur per railcar, three loading stations, and the density of molten sulfur (124.8 lb/SCF). These emissions are vented to the SRU incinerator and are incorporated into that limit as SO_2.

	H_2S	
	lb/hr	TPY
Emissions	1.7	7.6

Emissions from the WWTP Incinerator

The table below details the emissions for the WWTP Incinerator as authorized by Permit No. 93-023-O (M-1), emissions after the modification, and the change in emissions.

	NO_X		CO		PM_{10}		SO_2		VOC	
	lb/hr	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
Pre[1]	8.9	39.0	1.3	5.6	0.1	0.5	5.6	24.5	1.8	7.9
Post[2]	8.9	39.0	1.3	5.7	0.1	0.5	5.6	24.5	2.5	11.0
Change	**0.0**	**0.0**	**0.0**	**0.1**	**0.0**	**0.0**	**0.0**	**0.0**	**0.7**	**3.1**

1 Emissions from the WWTP Incinerator before the modification are based on the following:

NO_X - a maximum concentration of 355 ppmv NH_3 in the bioreactor off-gases, a flow rate of 198,000 SCFH, and a 95.0% combustion efficiency;

CO, VOC, & PM_{10} - are based on a flow rate of 27.89 lb/hr of VOC with a heating value of 21,344 BTU/lb, a combustion efficiency of 95%, and AP-42, Section 1.4 (7/98) emission factors;

SO_2 - a maximum concentration of 160 ppmv H_2S in the bioreactor off-gases, a flow rate of 198,000 SCFH, and a 95.0% combustion efficiency.

2 Emissions from the WWTP Incinerator after the modification are based on the following:

NO_X - a maximum concentration of 315 ppmv NH_3 in the bioreactor off-gases, a flow rate of 198,000 SCFH, and a 95.0% combustion efficiency plus an emissions factor of 0.12 lb/MMBTU and a heat rating of 15 MMBTUH;

CO, VOC, & PM_{10} - are based on a flow rate of 42.05 lb/hr of VOC with a heating value of 21,344 BTU/lb, a combustion efficiency of 95%, and AP-42, Section 1.4 (7/98) emission factors;

SO_2 - a maximum concentration of 160 ppmv H_2S in the bioreactor off-gases, a flow rate of 198,000 SCFH, and a 95.0% combustion efficiency.

Emissions from Heaters H-6503, H-302, H-402C, & H-408

The table below shows the estimated potential emissions for the process heaters and assumes 100% conversion of H_2S in the fuel gas to SO_2.

	NO_X		CO		PM_{10}		SO_2		VOC	
Heaters	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
H-6503	0.3	1.3	0.4	1.8	0.04	0.2	0.2	0.7	0.03	0.1
H-302	0.7	2.9	0.9	4.0	0.08	0.4	0.4	1.6	0.06	0.3
H-402C	1.2	5.3	1.7	7.2	0.15	0.7	0.7	2.9	0.11	0.5
H-408	0.7	3.2	1.0	4.3	0.09	0.4	0.4	1.8	0.06	0.3

Emissions are based on the following heat input ratings HHV (MMBTUH) and emission factors:

H-6503 - 5.0, H-302 - 11.0, H-402C - 20.0, H-408 - 12.0;

NO_X - 0.06 lb/MMBTUH;

CO, PM_{10}, & VOC - AP-42, Section 1.4 (7/98);

SO_2 - A fuel-gas H_2S concentration of 159 ppmv and a HHV of 800 BTU/SCF.

Emissions for the Diesel-Fired Emergency Water Pump Engines EWCP-1, -2, and -3

The table below details the emissions for the 660-hp Caterpillar 3412 diesel-fired emergency water pump engines.

	NO_X		CO		PM_{10}		SO_2		VOC	
EWCP	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
1	15.0	0.4	4.0	0.1	0.5	0.01	0.2	0.01	0.4	0.01
2	15.0	0.4	4.0	0.1	0.5	0.01	0.2	0.01	0.4	0.01
3	15.0	0.4	4.0	0.1	0.5	0.01	0.2	0.01	0.4	0.01
Totals	45.0	1.2	12.0	0.3	1.5	0.03	0.6	0.03	1.2	0.03

Emissions are based a fuel flow of 34.2 gallons per hour, a hating value of 19,300 BTU/lb, a density of 7.1 lb/gal, and 56 hours of operation a year each and the following factors:

NO_X, CO, & PM_{10}, VOC - AP-42, Section 3.4 (10/96);

SO_2 - AP-42, Section 3.4 (10/96) and a maximum sulfur content of 0.05% by weight.

Added Process Heater's Associated Fugitive Equipment Emissions

The table below summarizes the fugitive emissions from the equipment associated with the new process heaters. Potential emissions are based on estimated equipment counts and the average refinery emission factors.

	VOC	
	lb/hr	**TPY**
Emissions	0.3	1.4

Added SWS #3 Associated Fugitive Equipment Emissions

The table below summarizes the fugitive emissions from the equipment associated with the new SWS. Potential emissions are based on estimated equipment counts and the average refinery emission factors.

	VOC		H_2S		NH_3	
	lb/hr	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
Emissions	0.1	0.3	0.4	1.6	0.1	0.6

Added Heat Exchanger's (17) Associated Fugitive Equipment Emissions

The table below summarizes the fugitive emissions from the equipment associated with the new heat exchangers. Potential emissions are based on estimated equipment counts and the average refinery emission factors.

	VOC	
	lb/hr	**TPY**
Emissions	0.3	1.1

Added Steam Stripper's (3) Associated Fugitive Equipment Emissions
The table below summarizes the fugitive emissions from the equipment associated with the new steam Strippers. Potential emissions are based on estimated equipment counts and the average refinery emission factors.

	VOC	
	lb/hr	TPY
Emissions	0.3	1.3

WWTP Equipment Leaks – Fugitive Emissions
The table below summarizes the existing, added, and total fugitive emissions from the WWTP equipment leaks. Potential emissions are based on estimated equipment counts and the average refinery emission factors.

	VOC	
	lb/hr	TPY
Existing Emissions	1.1	4.7
Added Emissions	0.3	1.4
Totals	**1.4**	**6.1**

LPG Loading Operations Equipment Leaks – Fugitive Emissions
The table below summarizes the existing and potential fugitive emissions from the LPG loading operations. There is no increase in emissions at the loading rack due to improvements in the loading equipment.

	Pre Modification		Post Modification		Emission
	Throughput	Emissions	Throughput	Emissions	Changes
	BPY	TPY	BPY	TPY	TPY
Railcar Loading	857,513	14.7	1,500,000	13.3	**-1.4**
Tank Truck Loading	599,603	13.3	750,000	10.1	**-3.2**
Unloading	642,515	6.5	1,080,765	6.5	**0.0**

Added Fugitive Equipment Emissions Associated with the FCCU
The table below summarizes the fugitive emissions from the added equipment in the FCCU. Potential emissions are based on estimated equipment counts and the average refinery emission factors.

	VOC	
	lb/hr	TPY
Emissions	0.6	2.8

Added Fugitive Equipment Emissions Associated with the CFHT

The table below summarizes the fugitive emissions from the added equipment in the CFHT Unit. Potential emissions are based on estimated equipment counts and the average refinery emission factors.

	VOC		**H_2S**		**SO_2**	
	lb/hr	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
Emissions	0.1	0.5	<0.1	<0.1	<0.1	0.1

Added Fugitive Equipment Emissions Associated with the NHT

The table below summarizes the fugitive emissions from the added equipment in the NHT Unit. Potential emissions are based on estimated equipment counts and the average refinery emission factors.

	VOC		**H_2S**		**SO_2**	
	lb/hr	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
Emissions	0.1	0.5	<0.1	<0.1	<0.1	<0.1

Amine Regenerator/SRU/TGTU Unit #2 Wastewater Processing Fugitive VOC Emissions

Added emissions from the wastewater processing due to the new amine regeneration unit, SRU, and TGTU were estimated using a continuous flow of 0.0315 and WATER9.

	VOC		**H_2S**		**NH_3**	
	lb/hr	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
Emissions	0.8	3.6	0.2	0.8	0.1	0.5

SRU #2 Equipment Leaks – Fugitive VOC Emissions

The table below summarizes the fugitive emissions from the SRU #2 equipment leaks. Potential emissions are based on estimated equipment counts and the average refinery emission factors.

	VOC		**H_2S**		**SO_2**		**NH_3**	
	lb/hr	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
Emissions	0.7	2.9	0.6	2.4	0.1	0.4	0.1	0.3

Amine Regeneration Unit #2 Equipment Leaks – Fugitive VOC Emissions

The table below summarizes the fugitive emissions from the Amine Regeneration Unit #2 equipment leaks. Potential emissions are based on estimated equipment counts and the average refinery emission factors.

	VOC		**H_2S**		**SO_2**	
	lb/hr	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
Emissions	0.4	1.6	0.1	0.4	0.8	3.5

SRU Tail Gas Treating Unit #2 Equipment Leaks – Fugitive VOC Emissions

The table below summarizes the fugitive emissions from the SRU Tail Gas Treating Unit #2 equipment leaks. Potential emissions are based on estimated equipment counts and the average refinery emission factors.

	VOC		H_2S		SO_2	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
Emissions	0.6	2.5	0.1	0.4	0.3	1.3

TOTAL EMISSION INCREASES

	NO_X		CO		PM_{10}		SO_2		VOC		H_2S	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
Loading	----	----	----	----	----	----	----	----	0.6	2.6	----	----
Tanks	----	----	----	----	----	----	----	----	2.1	9.2	0.2	0.8
CCR	0.4	1.5	0.1	0.3	0.2	0.8	0.2	0.9	<0.1	0.1	----	----
SBH-001	4.0	17.4	1.1	4.6	0.3	1.3	26.2	114.7	0.2	1.0	----	----
SBH-002	1.0	4.3	1.7	7.2	0.2	0.7	0.6	2.7	0.1	0.5	----	----
TK-AB001	----	----	----	----	----	----	----	----	<0.1	<0.1	0.1	0.5
WWTP	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.7	3.1	0.2	0.6
H-6503	0.3	1.3	0.4	1.8	<0.1	0.2	0.2	0.7	<0.1	0.1	----	----
H-302	0.7	2.9	0.9	4.0	0.1	0.4	0.4	1.6	0.1	0.3	----	----
H-402C	1.2	5.3	1.7	7.2	0.2	0.7	0.7	2.9	0.1	0.5	----	----
H-408	0.7	3.2	1.0	4.3	0.1	0.4	0.4	1.8	0.1	0.3	----	----
EWCPs	45.0	1.2	12.0	0.3	1.5	<0.1	0.6	<0.1	1.2	<0.1	----	----
PH Fug.	----	----	----	----	----	----	----	----	0.3	1.4	----	----
SWS #3	----	----	----	----	----	----	----	----	0.1	0.3	0.4	1.6
HE Fug.	----	----	----	----	----	----	----	----	0.3	1.1	----	----
SS Fug.	----	----	----	----	----	----	----	----	0.3	1.3	----	----
WWTP Fug	----	----	----	----	----	----	----	----	0.3	1.4	----	----
FCCU Fug.	----	----	----	----	----	----	----	----	0.6	2.8	----	----
CFHT Fug.	----	----	----	----	----	----	<0.1	0.1	0.1	0.5	<0.1	<0.1
NHT Fug.	----	----	----	----	----	----	<0.1	<0.1	0.1	0.5	<0.1	<0.1
#2 WW	----	----	----	----	----	----	----	----	0.8	3.6	0.2	0.8
SRU #2	----	----	----	----	----	----	0.1	0.4	0.7	2.9	0.6	2.4
ARU #2	----	----	----	----	----	----	0.8	3.5	0.4	1.6	0.1	0.4
TGTU #2	----	----	----	----	----	----	0.3	1.3	0.6	2.5	0.1	0.4
Totals	**53.3**	**37.1**	**18.9**	**29.8**	**2.7**	**4.6**	**30.7**	**130.8**	**10.1**	**37.8**	**2.1**	**7.7**

SECTION V. PSD REVIEW

Emission increases of SO_2 are greater than the Prevention of Significant Deterioration (PSD) significance level (40 TPY). Therefore, the requirements of the PSD program must be addressed for this modification. Full PSD review of emissions consisted of the following:

1. A determination of best available control technology (BACT);
2. An evaluation of existing air quality and a determination concerning monitoring requirements;
3. An analysis of compliance with National Ambient Air Quality Standards (NAAQS);
4. An evaluation of PSD increment consumption;
5. An evaluation of source-related impacts on growth, soils, vegetation, and visibility;
6. And a Class I area impact evaluation.

A. Best Available Control Technology

A BACT analysis is required for all pollutants emitted above PSD-significance levels. Economic as well as energy and environmental impacts are considered in a BACT analysis. BACT is generally defined as “an emission limitation based on the maximum degree of reduction for each pollutant subject to regulation under the Act which would be emitted from any…source…which on a case-by-case basis is determined to be achievable taking into account energy, environmental, and economic impacts and other costs.” The EPA-required top-down BACT approach must look not only at the most stringent emission control technology previously approved, but it also must evaluate all demonstrated and potentially applicable technologies, including innovative controls, lower polluting processes, etc. The five basic steps of the top-down procedure are:

Step 1. Identify all control technologies
Step 2. Eliminate technically infeasible options
Step 3. Rank remaining control technologies by control effectiveness
Step 4. Evaluate most effective controls and document results
Step 5. Select BACT

The first step is to identify all "available" control options for each modification/EU which triggering PSD for each pollutant under review. Available control options are those technologies or techniques with a practical potential for application to the EU. During the course of the BACT analysis, one or more control options may be eliminated from consideration. However, at the outset, a comprehensive list must be compiled. This list should include potentially applicable Lowest Achievable Emission Rate (LAER) technologies, innovative technologies, and controls applied to similar source categories.

The second step of the top-down analysis is to arrange the comprehensive list, created in Step 1, based on technical feasibility. The technical evaluation should clearly document the difficulties based on source-specific factors and physical, chemical, and engineering principles that preclude the safe and successful use of the control option. Technically infeasible control technologies are removed from further evaluation.

In the third step, all remaining control alternatives not eliminated in Step 2 are ranked and listed in descending order of control effectiveness. A list should be prepared for each emissions unit for each pollutant subject to BACT review. If the top ranked control option is proposed as BACT, other considerations need not be detailed.

In the fourth step, energy, environmental, and economic impacts are considered in order to arrive at the level of control. Beginning with the most stringent control option, both beneficial and adverse impacts are discussed and quantified. This process continues until the technology under consideration cannot be eliminated by any source-specific adverse impacts.

The final step is the selection of the most effective control option not eliminated by the four preceding steps as BACT for the pollutant and EU under review.

The EPA has consistently interpreted statutory and regulatory BACT definitions as containing two core requirements that the agency believes must be met by any BACT determination, regardless of whether it is conducted in a "top-down" manner. First, the BACT analysis must include consideration of the most stringent available control technologies (i.e., those which provide the "maximum degree of emissions reduction"). Second, any decision to require a lesser degree of emissions reduction must be justified by an objective analysis of energy, environmental, and economic impacts.

The BACT analysis evaluates control technologies/techniques for the following pollutants emitted from the sources identified above:

1. SO_2 emissions from the SRU tail gases,
2. SO_2 emissions from the hot oil heater, and
3. SO_2 emissions from the fugitive equipment leaks.

All proposed and applied BACT must meet, at minimum, all applicable New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP). In some cases, technologies not sufficiently effective by themselves can be used in tandem to achieve BACT emission reduction levels.

Selected BACT

Source	**Pollutant**	**Selected BACT**
SRU Exhaust	SO_2	MDEA Regenerative Absorber TGTU & Incinerator
Heaters & Reboilers	SO_2	Refinery Fuel Gas w/H_2S concentration of 160 ppmv or less
Equipment Leaks	SO_2	LDAR

SO_2

<u>SRU</u>

The SRU will be subject to NSPS, Subpart J. The applicable NSPS maximum allowable emissions from an SRU are listed below:

NSPS Limits For the SRU

Pollutant	**Emission Limit**	**Reference**
SO_2	250 ppmv (dry basis) @ 0% O_2	40 CFR 60.104(a)(2)

The resources consulted in the compilation of potential options for SO_2 control for the Ardmore refinery SRU include the following:

- EPA's New Source Review Website
- U.S. EPA's RACT/BACT/LEAR Clearinghouse (RBLC) database
- The Maximum Achievable Control Technology (MACT) floor analysis included in the preamble to the proposed 40 CFR Part 63, Subpart UUU - *NESHAP for Petroleum Refineries – Catalytic Cracking (Fluid and Other) Units, Catalytic Reforming Units, and Sulfur Plants*
- Other refineries with similar process limits

Sulfur recovery (the conversion of H_2S to elemental sulfur) is usually accomplished using a modified Claus process, which consists of a thermal reactor and multi-stage catalytic reactors in series. First, one-third of the H_2S is burned with air in a thermal reactor furnace to yield SO_2. The SO_2 then reacts with H_2S in the presence of a catalyst to produce sulfur, water, and heat. Since the reaction is reversible, the reaction occurs in a series of catalytic reactors (or stages), and the vapors are cooled to condense the sulfur between each reactor driving the reaction towards completion. The Claus gas is then reheated prior to the next stage. The conversion efficiencies of an SRU range from 95% for a 2-stage to 96% for a 3-stage unit. The off-gases from the final condenser of the SRU or “tail gas” primarily consist of inert gases with less than 3% sulfur compounds (H_2S, SO_2, CS_2, and COS). The proposed SRU is a 4-Stage Claus combustion unit.

The SCOT™ TGTU proposed uses catalytic reduction (using a cobalt-molybdenum catalyst) of the tail gas sulfur compounds to H_2S followed by amine absorption to recover and recycle any H_2S present in the tail gas. The off-gases from the TGTU are usually incinerated to convert the remaining tail gas sulfur compounds to SO_2. Sulfur recovery efficiencies of catalytic reduction followed by amine recovery typically range from 92 to 97%. Therefore, the combined efficiency of the SRU and TGTU can exceed 99.7%. After incineration, the exhaust gases consist of inert gases with an SO_2 concentration of between 100 and 300 parts per million (ppm) with trace amounts of H_2S, COS, and CS_2.

Two types of control technologies are proposed for the top-down analysis for control of SO_2 emissions from the SRU Incinerator: a pre-incineration scrubbing system or a post-incinerator scrubbing system are the most feasible control technologies for the control of SO_2 emissions. For the cost analyses, the cost of the SRU, hot oil heater, and incinerator were not included.

1. Identification of Available Control Technologies

   a. Pre-Incineration SRU Scrubbing & TGTU
   b. Post-Incinerator Flue Gas Scrubbing without a TGTU

Wet Gas Scrubbers (WGSs)
WGSs chemically remove SO_2 emissions using an aqueous solution. Flue gas enters the scrubber where intensive gas/liquid contacting removes sulfur oxides by absorption, neutralization, or partial oxidation. Wet scrubbing is a widely used control technology because a high level of efficiency may be achieved and because the costs are low relative to comparable technologies. Pre-Incineration scrubbers use hydrogenation/reduction of the SRU tail gas and then adsorption or reduction to remove the sulfur compounds from the tail gas. Post-incineration scrubbers directly absorb the SO_2.

Dry Scrubber (with ESP or baghouse)
In a dry scrubbing system, a dry sorbent such as hydrated lime and water is injected into a venturi to remove SO_2 from the stream. Typically, lime slurry is injected into a venturi or duct to provide intimate mixing of flue gases and the sorbent. The SO_2 reacts with the sorbent in the wet phase. Inherent heat in the gas stream dries the slurry resulting in dry sorbent, which can be collected with an electrostatic precipitator (ESP) or fabric filter. The advantages of a dry scrubber include a reduction in water use and the generation of a dry waste that may be recyclable, depending on waste quality and regulatory classification and proximity of potential recyclers. One of the disadvantages of a dry scrubber is that it requires a secondary control device.

2. Eliminate Technically Infeasible Control Technologies

For the proposed control of SO_2 emissions from the incinerator, a pre-incineration front-end scrubbing system, or post-incinerator tail-end scrubbing system are the most feasible control technologies for the control of SO_2 emissions. Based on review of previous PSD permits, wet scrubbing systems are used extensively for controlling SO_2 emissions from SRUs and that type of control technology typically results in BACT. None of the SO_2 control technologies considered were eliminated as technically infeasible. However, control technologies that do not perform at an overall sulfur recovery efficiency equal to or greater than 99.8% were eliminated.

3. Rank Remaining Control Technologies

All of the available control technologies in conjunction with the SRU result in approximately the same overall reduction of sulfur from the amine regenerator off-gases of 99.8% and a tail gas SO_2 emission reduction of 97.3%. The final emission rate proposed by the applicant (NSPS, Subpart J limitation of 250 ppmv @ 0% O_2) can be met using different scrubbing solutions and different placement of the scrubbers.

Potential SO_2 Control Technologies

Control Technology	Est. Overall Control Efficiency
SCOT Reactor w/Regenerative MDEA Scrubber	99.9%
SCOT Reactor w/Regenerative Caustic Scrubber	99.9%
SCOT Reactor w/Non-Regenerative Caustic Scrubber	99.9%

4. Evaluate Remaining Control Technologies and Document Results

Pre-Incineration Tail-Gas Amine (MDEA) Scrubbing and Regeneration Unit.
Within the proposed SRU design, based on the material balance information, approximately 9,900 lbs/hr of sulfur will be processed by the Claus combustion unit. At the NSPS allowable of 250 ppmv @ 0% O2 the SRU with the TGTU and ARU will emit 26.2 lbs SO_2/hr or approximately 13.1 lbs S/hr. The overall sulfur recovery efficiency at this emission rate is approximately 99.9%. Additionally, included in the proposed NSPS allowable (26.2 lbs SO_2/hr) are emissions from the sulfur-pit vacuum sweep, the liquid sulfur storage-tank, and rail car loading emissions. The proposed amine tail gas treating and regeneration unit can meet, or exceed, the control efficiencies documented in the RBLC database.

The estimated total annualized cost associated with the installation of the SCOT reactor with a MDEA TGTU and supporting ARU is approximately six million dollars. The estimated cost effectiveness of the TGTU is approximately $1,476/ton at a recovery efficiency of 97.3% and the NSPS, Subpart J limitation of 250 ppmv. The amine based TGTU utilized in conjunction with the amine regenerator does not require the disposal of waste, utilizes less raw material (MDEA), and recovers a saleable raw material (sulfur). When the annual revenue of recovered sulfur is applied against the total annualized cost, the cost effectiveness of the system becomes approximately $841/ton. The required energy for this system is approximately 140 MMBTU/ton SO_2 based on the proposed design.

The estimated total annualized cost associated with the installation of the SCOT reactor with a caustic scrubber TGTU is approximately five and a half million dollars. The estimated cost effectiveness of the TGTU is approximately $1,314/ton at the same recovery efficiency of the MDEA TGTU and supporting ARU of 97.3% and the NSPS, Subpart J limitation of 250 ppmv. However, the caustic scrubber TGTU requires the disposal of waste (9,554 TPY) and utilizes more raw materials. The required energy for this system is approximately 88 MMBTU/ton SO_2.

Post-Incinerator Flue Gas Wet Scrubber w/no SCOT reactor and TGTU
The estimated total annualized cost of a post-incinerator scrubber without a SCOT reactor and TGTU is also approximately seven and a half million dollars. The estimated cost effectiveness of the post-incinerator scrubber is also approximately $1,763/ton at a recovery efficiency of 97.3% and the NSPS, Subpart J limitation of 250 ppmv. However, the post-incinerator wet scrubber depending upon the type of wet scrubber will either require waste treatment and disposal or secondary costs associated with control or treatment of a concentrated SO_2 stream. Disposal of waste generated from the post-incinerator wet scrubber (8,633 TPY) is environmentally undesirable and secondary treatment of a concentrated gas stream will increase

the estimated total annualized cost associated with post-incineration treatment. The required energy for this system is approximately 125 MMBTU/ton SO_2.

Considering the fact that both systems (pre- and post- incinerator control) operate at approximately the same efficiency and operational cost and the disadvantages of land filling solid waste, the amine-based pre-incineration scrubbing system is the preferred option. The extra energy required for the MDEA system is substantially less of an environmental impact than the resource and energies consumed land filling the wastes generated by the other systems.

Combined Pre-Incineration and Post-Incineration Scrubbing
The incremental effect of controlling the SO_2 emissions after scrubbing and incineration to a level below the NSPS, Subpart J emission level using a post-incineration scrubbing system was reviewed to determine the level of control for the SRU TGTU Incinerator. Based on a 90% control of the SO_2 emissions after incineration, the incremental cost effectiveness of this control option was calculated to be approximately $57,071/ton.

In reviewing and researching the best available control technologies for similar processes, the information contained within RBLC was reviewed. Four of the RBLC reviews relied on reducing emissions of SO_2 based on netting and process changes to reduce the facility allowable emissions while enabling construction/modification of the respective unit. Based on the review, the industry standard for an SRU, 6 considered, would result in a minimum required overall sulfur recovery efficiency of 99.8%. The most stringent control efficiency was determined to be 99.9% overall sulfur recovery. All of the control technologies reviewed utilized tail gas scrubbers followed by incineration of the tail-gas.

There is also an economic incentive to recover and recycle the sulfur in the untreated tail gas as opposed to releasing the sulfur, in the form of H_2S, COS, S_X, and C_2S to an incineration unit. SO_2 control technologies that generate a secondary waste that requires treatment and processing reduces the economic and environmental benefit of controlling SO_2 emissions.

5. Select BACT

Based on the information provided and a minimum overall sulfur recovery efficiency of 99.9%, the proposed SCOT unit, amine-based TGTU, amine regeneration unit, and incinerator are considered BACT. The proposed amine system and incinerator is evaluated to perform at approximately a 97.3% sulfur recovery efficiency and the SRU with the TGTU has an estimated overall sulfur recovery efficiency of 99.9% at the NSPS, Subpart J allowable emissions rate. The NSPS, Subpart J allowable emissions rate is also considered the MACT floor for the recently proposed 40 CFR Part 63, Subpart UUU - *NESHAP for Petroleum Refineries – Catalytic Cracking (Fluid and Other) Units, Catalytic Reforming Units, and Sulfur Plants*.

Proposed BACT Controls, Emission Limits, and Monitoring

Pollutant	Selected Technology	Emissions Limits	Proposed Monitoring
SO_2	Hydrogenation / Reduction and scrubbing with MDEA	250 ppmdv[1] @ 0% O_2 26.2 lb/hr[2] 115 tons/year	SO_2 continuous emission monitoring systems (CEMS). O_2 monitoring to correct the concentration to 0% O_2.

[1] – 12-hour rolling average of contiguous 1-hour averages.
[2] – 2-hour average of contiguous 1-hour averages.

<u>Heaters and Reboilers (SBH-002, H-6503, H-302, H-402C, & H-408)</u>

1. Identification of Available Control Technologies

The control technologies, listed on the following page, were identified for controlling SO_2 emissions from the heaters and reboilers. The SO_2 emissions from the TGTU Incinerator from combustion of auxiliary fuel are also addressed here instead of with the other SO_2 emissions from combustion of the waste gas in the TGTU Incinerator.

a. Pre-Combustion - Low-sulfur Fuels
b. Post-Combustion - Flue Gas Scrubbing

<u>Low Sulfur Fuels</u>
Nearly all of the sulfur contained in the fuel being combusted will be converted to SO_2, therefore, SO_2 emissions are reduced by limiting the sulfur content of the fuel.

<u>Flue Gas Scrubbing</u>
All of the post-combustion controls for emissions of SO_2 include some sort of flue gas scrubbing using different types of scrubbing solutions or slurries. These include the lime/limestone, double alkali, Wellman-Lord, magnesium oxide, and citrate flue gas desulfurization processes. Some of these processes are regenerable and others are non-regenerable. Some require additional controls after the flue gas scrubbing such as condensers, baghouses, and waste treatment. In reviewing these controls for SO_2 emissions from the heaters and reboilers, an average case was used to calculate the economic impact resulting from installation of a flue gas scrubbing unit.

2. Eliminate Technically Infeasible Control Technologies

All possible controls were considered technically feasible. Post combustion control of the TGTU emissions was addressed in the SRU section. As an example for calculation of the cost associated with control of the SO_2 emissions from the heaters and reboilers, a general case was reviewed to determine the average cost of a scrubbing system. The lime/limestone scrubbing system was used as an average case for reviewing the economic impact of installing the scrubbing unit.

3. Rank Remaining Control Technologies

Potential SO_2 Control Technologies

Control Technology	Estimated Control Efficiency
Lime/Limestone Scrubbing	95%
Fuel Specification: Low Sulfur Fuels	Base Case

4. Evaluate Remaining Control Technologies and Document Results

No energy/environmental impacts were identified to preclude any control option from review. Because flue gas scrubbing is considered to be technically feasible, add-on controls were not eliminated. The cost effectiveness for a flue gas scrubber was calculated using the average control technology based on the "EPA Air Pollution Control Cost Manual," Sixth Edition cost estimates.

Flue Gas Scrubber				
Source	Uncontrolled Emissions (TPY)	Emissions Reduction (TPY)	Annualized Cost ($/year)	Cost Effectiveness ($/ton)
SBH-002	2.7	2.6	91,000	35,000
H-6503	0.7	0.7	91,000	130,000
H-302	1.6	1.5	91,000	60,667
H-402C	2.9	2.8	91,000	32,500
H-408	1.8	1.7	91,000	53,529

The RBLC and recently issued permits in attainment areas were reviewed for recent determinations. The reviewed determinations did not result in flue gas scrubbing as BACT for small heaters. Therefore, based on the associated costs and recent determinations; flue gas scrubbing was eliminated from consideration. The RBLC database lists fuel sulfur content limits as the most prevalent form of BACT for controlling SO_2 emissions from refinery fuel gas-fired heaters and incinerators.

5. Select BACT

Based on this review, limiting the H_2S content of the refinery fuel-gas fired in the heaters, reboilers, and the auxiliary fuel for the TGTU Incinerator to the NSPS, Subpart J limitation of 160 ppmv is acceptable as BACT.

Proposed BACT Controls, Emission Limits, and Monitoring

Pollutant	Selected Technology	Fuel Sulfur Content Limit	Proposed Monitoring
SO_2	Low Sulfur Fuel NSPS, Subpart J	160 ppmdv[1]	H_2S continuous monitoring system.

[1] – 3-hour rolling average of contiguous 1-hour averages.

Fugitive Equipment Leaks

There are no identified control technologies for SO_2 emissions from fugitive equipment leaks. The majority of the SO_2 emissions from fugitive equipment leaks come from flaring of H_2S emissions from pressure relief valves. Leak detection and repair (LDAR) programs are the most prevalent form of BACT for controlling fugitive VOC emissions from process equipment. All of the equipment in VOC or HAP service at this facility will either be subject to NSPS, Subpart GGG, or NESHAP, Subpart CC. Since there are no control technologies identified for control of SO_2 emissions from fugitive equipment leaks, compliance with the applicable VOC/HAP LDAR programs will act as surrogates for control of SO_2 emissions from fugitive equipment leaks. Therefore, meeting the applicable LDAR requirements for the fugitive equipment sources is acceptable as BACT.

B. Air Quality Impacts

The Valero Ardmore Refinery is located in Carter County, which is currently designated attainment or unclassified for all criteria pollutants, and there are no areas classified as non-attainment within 50 kilometers of the refinery. This modification will result in emission increases of SO_2 sufficient to trigger the Prevention of Significant Deterioration (PSD) requirements codified in 40 CFR Part 52.

Prevention of Significant Deterioration (PSD) is a construction-permitting program designed to ensure air quality does not degrade beyond the NAAQS or beyond specified incremental amounts above a prescribed baseline level. The PSD rules set forth a review procedure to determine whether a source will cause or contribute to a violation of the NAAQS or maximum increment consumption levels. If a source has the potential to emit a pollutant above the PSD significance levels, then they trigger this review process. EPA has provided modeling significance levels (MSL) for the PSD review process to determine whether a source will cause or contribute to a violation of the NAAQS or consume increment. Air quality impact analyses were conducted to determine if ambient impacts would be above the EPA defined modeling and monitoring significance levels. If impacts are above the MLS, a radius of impact (ROI) is defined for the facility for each pollutant out to the farthest receptor at or above the significance levels. If a radius of impact is established for a pollutant, then a full impact analysis is required for that pollutant. If the air quality analysis does not indicate a radius of impact, no further air quality analysis is required for the Class II area.

Valero has prepared an air quality analysis in accordance with the procedures and methodology presented, which are consistent with guidance provided by the Oklahoma Department of Environmental Quality (ODEQ) and Environmental Protection Agency (EPA). The results of this air quality analysis show that the proposed emissions authorized in this permit will not cause or contribute to an exceedance of the NAAQS or significant PSD increment consumption.

Modeling Methodology

The refined air quality modeling analyses for the Valero Ardmore Refinery employed USEPA's Industrial Source Complex (ISC3) (Version 02035) model (USEPA, 1995a). The ISC3 model is recommended as a guideline model for assessing the impact of aerodynamic downwash (40 CFR 40465-40474). The regulatory default option was selected such that USEPA guideline requirements were met.

The stack height regulations promulgated by USEPA on July 8, 1985 (50 CFR 27892), established a stack height limitation to assure that stack height increases and other plume dispersion techniques would not be used in lieu of constant emission controls. The regulations specify that Good Engineering Practice (GEP) stack height is the maximum creditable stack height which a source may use in establishing its applicable State Implementation Plan (SIP) emission limitation. For stacks uninfluenced by terrain features, the determination of a GEP stack height for a source is based on the following empirical equation:

$$H_g = H + 1.5L_b$$

where:

H_g = GEP stack height;
H = Height of the controlling structure on which the source is located, or nearby structure; and
L_b = Lesser dimension (height or width) of the controlling structure on which the source is located, or nearby structure.

Both the height and width of the structure are determined from the frontal area of the structure projected onto a plane perpendicular to the direction of the wind. The area in which a nearby structure can have a significant influence on a source is limited to five times the lesser dimension (height or width) of that structure, or within 0.5 mile (0.8 km) of the source, whichever is less. The methods for determining GEP stack height for various building configurations have been described in USEPA's technical support document (USEPA, 1985).

The heights of some of the exhaust stacks at the refinery were evaluated to determine if they are less than respective GEP stack heights, a dispersion model to account for aerodynamic plume downwash was necessary in performing the air quality impact analyses.

Since downwash is a function of projected building width and height, it is necessary to account for the changes in building projection as they relate to changes in wind direction. Once these projected dimensions are determined, they can be used as input to the ISC3 model.

In October 1993, USEPA released the Building Profile Input Program (BPIP) to determine wind direction-dependent building dimensions. The BPIP program was used to determine the wind direction-dependent building dimensions for input to the ISC3 model.

The BPIP program builds a mathematical representation of each building to determine projected building dimensions and its potential zone of influence. These calculations are performed for 36 different wind directions (at 10 degree intervals). If the BPIP program determines that a source is under the influence of several potential building wakes, the structure or combination of structures that has the greatest influence ($H + 1.5\ L_b$) is selected for input to the ISCST3 model. Conversely, if no building wake effects are predicted to occur for a source for a particular wind direction, or if the worst-case building dimensions for that direction yield a wake region height less than the source's physical stack height, building parameters are set equal to zero for that wind direction. For this case, wake effect algorithms are not exercised when the model is run. The building wake criteria influence zone is 5 L_b downwind, 2 L_b upwind, and 0.5 L_b crosswind. These criteria are based on recommendations by USEPA. The building cavity effects were then used in the modeling analysis for the refinery. For this analysis, the first step was to determine the building cavity height based on the formula:

$$h_c = H + 0.5L_b$$

where:

h_c = GEP stack height;

H = Height of the controlling structure on which the source is located, or nearby structure; and

L_b = Lesser dimension (height or width) of the controlling structure on which the source is located, or nearby structure.

If the stack height was greater than or equal to the cavity height, the cavity effect would not affect the downwind maximum impacts.

The meteorological data used in the dispersion modeling analyses consisted of five years (1986, 1987, 1988, 1990, and 1991) of hourly surface observations from the Oklahoma City, Oklahoma, National Weather Service Station and coincident mixing heights from Oklahoma City (1986-1988) and Norman, Oklahoma (1990 and 1991).

Surface observations consist of hourly measurements of wind direction, wind speed, temperature, and estimates of ceiling height and cloud cover. The upper air station provides a daily morning and afternoon mixing height value as determined from the twice-daily radiosonde measurements. Based on NWS records, the anemometer height at the Oklahoma City station during this period was 6.1 meters.

Prior to use in the modeling analysis, the meteorological data sets were downloaded from the USEPA Support Center for Regulatory Air Models (SCRAM) website. This data was scanned for missing data, but no missing data was found. USEPA procedures outlined in the USEPA document, “Procedures for Substituting Values for Missing NWS Meteorological Data for Use in Regulatory Air Quality Models,” were used to fill gaps of information for single missing days. For larger periods of two or more missing days, seasonal averages were used to fill in the missing periods. The USEPA developed rural and urban interpolation methods to account for the effects of the surrounding area on development of the mixing layer boundary. The rural scheme was used to determine hourly mixing heights representative of the area in the vicinity of the refinery.

The urban/rural classification is used to determine which dispersion parameter to use in the model. Determination of the applicability of urban or rural dispersion is based upon land use or population density. For the land use method the source is circumscribed by a three kilometer radius circle, and uses within that radius analyzed to determine whether heavy and light industrial, commercial, and common and compact residential, comprise greater than 50 percent of the defined area. If so, then urban dispersion coefficients should be used. The land use in the area of the proposed facility is not comprised of greater than 50 percent of the above land use types and is considered a rural area.

The refined modeling used a nested Cartesian grid. Receptors were placed no greater than 50 meters apart along the boundary. From the fenceline, a 100-meter grid of receptors extended out to 1,000 meters. A 500-meter grid extended beyond this grid, out to 2.5 kilometers from the site. A 1,000-meter grid extended beyond this grid, out to 10 kilometers from the site. Beyond that, a spacing of 2.5 kilometers was used extending out to 50 kilometers from the facility. This modeling was used to define the radius of significant impact for each pollutant. All receptors were modeled with actual terrain data. The terrain data was taken from United States Geologic Survey (USGS) 7.5-minute Digital Elevation Model Files.

<u>Summary of Modeling Emission Inventory</u>

For each modeling analysis type (e.g., Preliminary Analysis, NAAQS or PSD Increment) varying modeling emission inventories were developed (e.g. contemporaneous increases, increases over baseline, or total emissions). However, the stack parameters for point sources in each inventory were modeled using actual stack parameters, with the exception of some psuedo-point type sources (e.g., tanks), that were modeled to represent their non-buoyant, low velocity type emissions. A discussion of the sources included in each modeling analysis is presented below.

Preliminary Analysis

Typically for PSD Preliminary Analyses, contemporaneous changes (i.e., changes within three years of the triggering event) in emissions are modeled. However, an evaluation of historic changes at the Refinery in the review, and issuance, of 98-172-C (PSD), effective January 2003, revealed that changes at the facility that occurred as early as 1982 and required permitting under PSD regulations. The contemporaneous changes of emissions modeled for Permit No. 98-172-C (PSD) included all other changes at the facility. For the purpose of this review and the AOI, only the added sources for this project were modeled.

On-Property Sources – Full Impact Analyses

Available air permitting and emissions inventory documentation was reviewed to identify on-property sources of SO_2. For the NAAQS analyses, the identified on-property sources were modeled at their proposed allowable emission rates. For the PSD Increment analyses, the identified on-property sources were modeled at their increment-consuming emission rate. The increment-consuming emission rate was estimated by subtracting the historical two-year average emission rate from the proposed allowable emission rate. The on-property source emission inventories for the Full Impact Analyses were provided in the application.

Off-Property Sources – Full Impact Analyses
Off-property sources located within a radius defined by the AOI plus 50 kilometers were included in the Full Impact PSD Increment and NAAQS Analyses that were triggered by the Preliminary Analysis. An ODEQ database retrieval, ODEQ emission inventory reports, and ODEQ permitting files were used to identify applicable sources to be included in the modeling analyses and their respective stack parameters and emission rates. Off-property sources were assumed to be increment consuming and allowable emission rates were included in the model.

Due to its proximity to the Refinery (contiguous to the south), sources at Atlas were evaluated to assess whether they were increment-consuming sources or whether they were existing emission sources prior to the minor source baseline date. Information from Atlas permit applications was used to assess construction, reconstruction, and modification dates for Atlas' emission sources. A summary of the analysis that was used to evaluate the sources included in the PSD Increment Analysis for each pollutant and a summary of the off-property modeling emission inventories for the impact analyses (PSD Increment and NAAQS) were provided in the application.

Preliminary Analysis
The first step in the PSD modeling analysis was the Preliminary Analysis (AOI analysis). In this analysis, emission increases were modeled to evaluate whether the resultant highest predicted concentrations for each pollutant averaging period combination were of regulatory significance.

These results were also used to evaluate the extent of the modeling analysis that would be required. A significant receptor file was created using either the ISCST3 "MAXIFILE" output option and/or BEE-Line's graphical (*.grf) interface for the ISCST3 model. This file contained each predicted concentration that was greater than the MSL, the receptor location, time, date and year. The results of the Preliminary Analysis were used to evaluate whether a Full Impact Analysis was required to define the resultant AOI for modeling purposes, and to evaluate whether a full analysis would be required. The results of the Preliminary Analysis are summarized on the following page.

Preliminary Analysis Results

Pollutant	Averaging Period	Max. Predicted Concentration (μg/m^3)	PSD MSL (μg/m^3)	AOI (km)	Monitoring Exemption Levels (μg/m^3)
SO_2	3-hour	90.3	25	2.2	N/A
	24-hour	19.8	5	2.9	13
	Annual	1.4	1	1.1	N/A

The results predicted ambient SO_2 concentrations to be greater than the MSL for all averaging periods. Since regulatory-significant concentrations were predicted for SO_2 for the applicable averaging periods greater than the modeling significance level, a full impact analysis was performed for each averaging period.

Full Impact Analysis (PSD Increment and NAAQS)
A Full Impact Analysis was performed to predict ambient concentrations for comparison to the NAAQS and PSD increment. This modeling analysis addressed emissions from the Valero Refinery's sources and off-property sources within the radius defined by the AOI plus 50 kilometers. The highest second high impacts were evaluated for the SO_2 short-term PSD Full Impact Analyses. The highest annual concentrations were evaluated for the long-term analyses.

Air Quality Monitoring Data
The preliminary modeling conducted as part of this analysis resulted in predicted concentrations that were above the modeling significance levels for the SO_2 3-hour, 24-hour, and annual averaging periods. Background concentration data was obtained from the ODEQ, Air Quality Division for each of the applicable averaging periods. Air Quality allowed the use of monitoring data collected from the Ponca City Area. Ponca City and Ardmore are of a similar size and have similar types of sources. The Ponca City area is actually a more heavily affected SO_2 area since the Conoco Refinery processes approximately three times the amount of crude oil and there are other sources of SO_2 emissions that impact the monitor. The 2002 monitoring data shown below should provide conservative background data for the NAAQS analysis. The refinery is located in an area that is generally free from the impact of other SO_2 point and area sources and the area impacted by the refinery is not an area of complex terrain.

Summary of Background Concentrations

Pollutant	Averaging Period	Monitored Concentration ($\mu g/m^3$)
SO_2	3-hour	120
	24-hour	76
	Annual	10

The background concentrations were added to the modeled results to demonstrate compliance with the NAAQS and increment consumption. Post-construction monitoring will not be required since the calculated impacts from all sources plus the background concentrations do not threaten the NAAQS or PSD Increments.

SO_2 NAAQS Analysis
A summary of the 3-hour, 24-hour, and annual SO_2 NAAQS modeling analyses is provided below.

SO_2 NAAQS Analysis Results

Averaging Period	NAAQS ($\mu g/m^3$)	Background ($\mu g/m^3$)	Max. Predicted Concentration ($\mu g/m^3$)	Predicted Conc. & Background ($\mu g/m^3$)
3-hour	1,300	120	587	707
24-hour	365	76	144	220
Annual	80	10	21	31

The highest predicted ambient concentration plus background was less than the NAAQS for all averaging periods. Thus, no further analysis was required.

SO_2 PSD Increment Analysis
A summary of the annual SO_2 PSD increment modeling analysis is provided below.

SO_2 Increment Analysis Results

Averaging Period	Maximum Predicted Conc. ($\mu g/m^3$)	PSD Increment ($\mu g/m^3$)
3-hour	143	512
24-hour	60	91
Annual	7	20

The highest predicted ambient concentrations were less than the PSD increment for all averaging periods. Thus, no further analysis was required.

F. Evaluation of Source-Related Impacts on Growth, Soils, Vegetation, & Visibility

Mobile Sources
Current EPA policy is to require an emissions analysis to include mobile sources. In this case, mobile source emissions are expected to be negligible. The number of employees needed beyond those currently employed is insignificant.

Growth Impacts
The purpose of the growth impact analysis is to quantify the possible net growth of the population of the area as a direct result of the project. This growth can be measured by the increase in residents of the area, the additional use and need of commercial and industrial facilities to assist the additional population with everyday services, and other growth, such as additional sewage treatment discharges or motor vehicle emissions.

Approximately 50 trade jobs (i.e., welders, electricians, construction workers, etc.) over a 24 month period will be needed to complete the construction of the project. It is anticipated that the majority of these jobs will be local hires, thus not requiring any additional residential or commercial capacity within the area. No full-time positions are expected. There should be no increase in community growth or the need for additional infrastructure. Therefore, it is not anticipated that the project will result in an increase in secondary emissions associated with non-project related activities or growth.

Ambient Air Quality Impact Analysis
The purpose of this aspect of impact analysis is to predict the air quality in the area of the project during construction and after commencing operation. This analysis follows the growth analysis by combining the associated growth with the emissions from the proposed project and the emissions from other permitted sources in the area to predict the estimated total ground-level concentrations of pollutants as a result of the project, including construction.

The only source of additional emissions may be from fugitive dust generated from equipment transportation or vehicles during construction. Any long-term air quality impact in the area will result from emissions increases due to operation of the facility. These impacts have been analyzed in preceding sections.

Soils and Vegetation Impact

The primary soil units in the area of the Refinery are Amber very fine sandy loam and Dale silt loam. The main crops typically grown on the soils identified within the area of interest are native grasses, and cultivated crops. No sensitive aspects of the soil and vegetation in this area have been identified. As such, the secondary NAAQS, which establish ambient concentration levels below which it is anticipated that no harmful effects to either soil or vegetation can be expected, are used as the benchmark for this analysis.

The effects of gaseous air pollutants on vegetation may be classified into three rather broad categories: acute, chronic, and long-term. Acute effects are those that result from relatively short (less than 1 month) exposures to high concentrations of pollutants. Chronic effects occur when organisms are exposed for months or even years to certain threshold levels of pollutants. Long-term effects include abnormal changes in ecosystems and subtle physiological alterations in organisms. Acute and chronic effects are caused by the gaseous pollutant acting directly on the organism, whereas long-term effects may be indirectly caused by secondary agents such as changes in soil pH.

SO_2 enters the plant primarily through the leaf stomata and passes into the intercellular spaces of the mesophyll, where it is absorbed on the moist cell walls and combined with water to form sulfurous acid and sulfite salts. Plant species show a considerable range of sensitivity to SO_2. This range is the result of complex interactions among microclimatic (temperature, humidity, light, etc.), edaphic, phenological, morphological, and genetic factors that influence plant response (USEPA, 1973).

The secondary NAAQS are intended to protect the public welfare from adverse effects of airborne effluents. This protection extends to agricultural soil. The modeling conducted, which demonstrated compliance with the Primary NAAQS simultaneously demonstrated compliance with the Secondary NAAQS because the Secondary NAAQS are higher or equal to the Primary NAAQS. Since the secondary NAAQS protect impact on human welfare, no significant adverse impact on soil and vegetation is anticipated.

Visibility Impairment

Visibility is affected primarily by PM and NO_X emissions. The area near the facility is primarily agricultural, consisting of pastureland. Some residences are located southeast and east of the facility. The closest airport is located approximately 3 miles north-northeast of the facility. Therefore, there are no airports, scenic vistas, or other areas that would be affected by minor reductions in visibility. The project is not expected to produce any perceptible visibility impacts in the vicinity of the plant. The project is actually expected to reduce visibility impacts of the existing facility. EPA computer software for visibility impacts analyses, intended to predict distant impacts, terminates prematurely when attempts are made to determine close-in impacts. It is concluded that there will be minimal impairment of visibility resulting from the facility's emissions. Given the limitation of 20% opacity of emissions, and a reasonable expectation that normal operation will result in 0% opacity, no local visibility impairment is anticipated.

G. Class I Area Impact Analysis

A further requirement of PSD includes the special protection of air quality and air quality related values (AQRV) at potentially affected nearby Class I areas. Assessment of the potential impact to visibility (regional haze analysis) is required if the source is located within 100 km of a Class I area. The Refinery is not within 100 km of the nearest Class I area, which is the Wichita Mountains Natural Wildlife Refuge (WMNWR). The Refinery is approximately 143 km from the WMNWR. Therefore, the Refinery was not evaluated for its impacts on the WMNWR.

SECTION VI. OKLAHOMA AIR POLLUTION CONTROL RULES

OAC 252:100-1 (General Provisions) [Applicable]
Subchapter 1 includes definitions but there are no regulatory requirements.

OAC 252:100-3 (Air Quality Standards and Increments) [Applicable]
Primary Standards are in Appendix E and Secondary Standards are in Appendix F of the Air Pollution Control Rules. At this time, all of Oklahoma is in attainment of these standards.

OAC 252:100-4 (New Source Performance Standards) [Applicable]
Federal regulations in 40 CFR Part 60 are incorporated by reference as they exist on July 1, 2002, except for the following: Subpart A (Sections 60.4, 60.9, 60.10, and 60.16), Subpart B, Subpart C, Subpart Ca, Subpart Cb, Subpart Cc, Subpart Cd, Subpart Ce, Subpart AAA, and Appendix G. These requirements are addressed in the “Federal Regulations” section.

OAC 252:100-5 (Registration of Air Contaminant Sources) [Applicable]
Subchapter 5 requires sources of air contaminants to register with Air Quality, file emission inventories annually, and pay annual operating fees based upon total annual emissions of regulated pollutants. Emission inventories have been submitted and fees paid for the past years.

OAC 252:100-8 (Permits for Part 70 Sources) [Applicable]
Part 5 includes the general administrative requirements for part 70 permits. Any planned changes in the operation of the facility which result in emissions not authorized in the permit and which exceed the “Insignificant Activities” or “Trivial Activities” thresholds require prior notification to AQD and may require a permit modification. Insignificant activities mean individual EU that either are on the list in Appendix I (OAC 252:100) or whose actual calendar year emissions do not exceed the following limits:

1. 5 TPY of any one criteria pollutant
2. 2 TPY of any one hazardous air pollutant (HAP) or 5 TPY of multiple HAPs or 20% of any threshold less than 10 TPY for single HAP that the EPA may establish by rule
3. 0.6 TPY of any one Category A toxic substance
4. 1.2 TPY of any one Category B toxic substance
5. 6.0 TPY of any one Category C toxic substance

Emission and operating limitations have been established based on information in the permit application and Permit No. 98-172-C (M-14) (PSD).

OAC 252:100-9 (Excess Emission Reporting Requirements) [Applicable]
In the event of any release which results in excess emissions, the owner or operator of such facility shall notify the Air Quality Division as soon as the owner or operator of the facility has knowledge of such emissions, but no later than 4:30 p.m. the next working day. Within ten (10) working days after the immediate notice is given, the owner operator shall submit a written report describing the extent of the excess emissions and response actions taken by the facility. Part 70/Title V sources must report any exceedance that poses an imminent and substantial danger to public health, safety, or the environment as soon as is practicable. Under no circumstances shall notification be more than 24 hours after the exceedance.

OAC 252:100-13 (Prohibition of Open Burning) [Applicable]
Open burning of refuse and other combustible material is prohibited except as authorized in the specific examples and under the conditions listed in this subchapter.

OAC 252:100-17 (Incinerators) [Not Applicable]
This subchapter specifies design and operating requirements and emission limitations for incinerators, municipal waste combustors, and hospital, medical, and infectious waste incinerators. Thermal oxidizers, flares, and any other air pollution control devices are exempt from this subchapter. The refinery does not have any incinerators besides the control devices used at the refinery.

OAC 252:100-19 (Particulate Matter) [Applicable]
This subchapter specifies a particulate matter (PM) emission limitation of 0.6 lb/MMBTU from fuel-burning units with a rated heat input of 10 MMBTUH or less. All of the small (<10 MMBTUH) fuel-burning units are fired with refinery fuel-gas. Fuel-burning equipment with a rated heat input between 10 and 1,000 MMBTUH are limited to between 0.599 and 0.20 lb/MMBTU as defined in Appendix C. The following table lists all fuel-burning equipment affected by this permit and their associated emissions.

Fuel-burning unit is defined as “any internal combustion engine or gas turbine or any other combustion device used to convert the combustion of fuel into usable energy.” Since flares and incinerators are pollution control devices designed to destroy pollutants and are not used to convert fuel into usable energy, they do not meet the definition of fuel-burning unit and are not subject to these requirements.

EU	Type of Unit	MMBTUH	SC 19 Limit (lb/MMBTU)	Emissions lb/MMBTU
H-601	Process Heater	50.4	0.41	0.01
H-901	Process Heater	51.9	0.41	0.01
H-103	Process Heater	102.6	0.36	0.01
H-301	Process Heater	22.5	0.50	0.01
B-801	Boiler	72.5	0.38	0.01
SBH-002	Hot Oil Heater	20.0	0.51	0.01
H-6503	Co-Processor Heater	5.0	0.60	0.01
H-302	Sat-Gas Debutanizer Reboiler	11.0	0.59	0.01
H-402C	NHT Stripper Reboiler	20.0	0.51	0.01
H-408	NHT Reactor Inter-Heater	12.0	0.58	0.01
EWCP-1	Caterpillar 3412	4.7	0.60	0.10
EWCP-2	Caterpillar 3412	4.7	0.60	0.10
EWCP-3	Caterpillar 3412	4.7	0.60	0.10

AP-42 (7/98), Section 1.4, Table 1.4-2, lists the total PM emissions for natural gas to be 7.6 lb/MMft^3 or about 0.0076 lb/MMBTU. The permit requires the use of refinery fuel-gas to ensure compliance with Subchapter 19. Since all of the emission limits for the heaters and reboilers under Subchapter 19 are greater than the expected emissions from these units, having the permit require these units to only be fueled with refinery fuel gas will ensure compliance with this subchapter 19. AP-42 (10/96), Section 3.4, Table 3.4-1, lists the total PM emissions for diesel-fired engines to be 0.1 lb/MMBTU. The permit requires the use of diesel fuel in the emergency fire-water pump engines to ensure compliance with Subchapter 19.

This subchapter also limits emissions of PM from directly fired fuel-burning units and industrial processes based on their process weight rates. For process rates up to 60,000 lb/hr (30 TPH), the emission rate in pounds per hour (E) is not to exceed the rate calculated using the process weight rate in tons per hour (P) and the formula in appendix G ($E = 4.10*P^{(0.67)}$). Listed in the following table are the process weight rates for the EUs affected by this permit, the estimated emissions, and the allowable emission limits.

EU	Source	Rate (TPH)	SC 19 Limit (lb/hr)	Emissions (lb/hr)
CCR	Platformer CCR Vent	0.50	2.58	0.56
SHB-001	SRU/TGTU w/Incinerator	21.2	31.73	0.40
HI-8801	WWTP Incinerator	0.01	0.23	0.12

The SRU tail gas incinerator only combusts waste gases and refinery fuel-gas as auxiliary fuel. No specific requirements are needed to ensure compliance with this subchapter. PM emissions from the Platformer CCR are controlled using a series of internal screens and cyclones. Since the catalyst is very expensive, every effort is made to recover it and minimize air emissions. Currently, there are no indirect operating parameters that can be measured to ensure operation of the screens and cyclones.

OAC 252:100-25 (Visible Emissions and Particulate Matter) [Applicable]
No discharge of greater than 20% opacity is allowed except for short-term occurrences, which consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case, shall the average of any six-minute period exceed 60% opacity. When burning refinery fuel-gas in the combustion units (process heaters and boilers) there is little possibility of exceeding the opacity standards.

OAC 252:100-29 (Fugitive Dust) [Applicable]
No person shall cause or permit the discharge of any visible fugitive dust emissions beyond the property line on which the emissions originate in such a manner as to damage or to interfere with the use of adjacent properties, or cause air quality standards to be exceeded, or interfere with the maintenance of air quality standards. Under normal operating conditions, this facility will not cause a problem in this area, therefore it is not necessary to require specific precautions to be taken.

OAC 252:100-31 (Sulfur Compounds) [Applicable]
Part 2 limits the ambient air impact of sulfur dioxide (SO_2) emissions from any one existing source or any one new petroleum and natural gas process source subject to OAC 252:100-31-26(a)(1). This part also limits the impact of H_2S emissions from any new or existing source. Recent modeling conducted using ISCST3 was used to show the impacts of the facility on the ambient air as shown in the following tables.

Ambient Impacts of SO_2 (Preliminary Analysis)

Averaging Time	**Standard μg/m³**	**Impact μg/m³**
5-minute*	1,300	1,072
1-hour*	1,200	652
3-hour	650	587
24-hour	130	119

* - Based on the PSD modeling preliminary analysis and adjustment factors for different averaging periods.

Ambient Impacts of H_2S (TV Application)

Averaging Time	**Standard μg/m³**	**Impact μg/m³**
24-hour	278	22

Emissions from all of the equipment have been modeled and have been shown to be in compliance with these standards.
Part 5 limits SO_2 emissions from new fuel-burning equipment (constructed after July 1, 1972). For gaseous fuels the limit is 0.2 lb/MMBTU heat input. This is equivalent to approximately 0.2 weight percent sulfur in the fuel gas which is equivalent to 2,000 ppm sulfur. All fuel-burning equipment constructed or modified after June 11, 1973, which combust refinery fuel gas are subject to NSPS, Subpart J, which limits the amount of H_2S in the fuel gas to 0.1 grains/DSCF or approximately 160 ppm. The refinery fuel gas has a HHV of approximately 800 BTU/SCF,

which is equivalent to approximately 0.0357 lb/MMBTU. The permit will require the use of refinery fuel gas with a limit of 160 ppm.

Part 5 requires removal or oxidation of H_2S from the exhaust gas of any new petroleum or natural gas process equipment. Oxidation of the H_2S must be conducted in a system that assures at least a 95% reduction of the H_2S in the exhaust gases and that is equipped with an alarm system to signal non-combustion of the exhaust gases. This does not apply to EUs that emit less than 0.3 lb/hr of H_2S. Emissions from the liquid sulfur storage tank and the regenerated amine storage tank are estimated below the exemption level. However, the liquid sulfur storage tank will be vented to the SRU incinerator. The railcar loading operations are calculated to have emissions of approximately 0.58 lb/hr/railcar based on the maximum loading rate and is subject to this requirement. For facilities with an SRU prior to release Subchapter 31 requires the SRU to meet a calculated sulfur reduction efficiency based on the SRU capacity. The new SRU will have a capacity of approximately 130 LTD. The required SO_2 reduction efficiency for units with a capacity greater than 5 LTD but less than 150 LTD is calculated using the following formula: $Z = 92.34 \times (X^{0.00774})$, where X is the sulfur feed rate in LTD. Based on this formula and the capacity of the new SRU, the required sulfur reduction efficiency is 95.9%. The SRU reduction efficiency is expected to exceed 99.8%. All applicable requirements will be incorporated into the permit.

OAC 252:100-33 (Nitrogen Oxides) [Not Applicable]

NO_X emissions are limited to 0.20 lb/MMBTU from all gas-fired fuel-burning equipment constructed after February 2, 1972, with a rated heat input of 50 MMBTUH or greater. The CCR and incinerators do not meet the definition of fuel-burning equipment and are not subject to this subchapter. EU H-901 is grandfathered and not subject to this subchapter.

EU	Type of Unit	MMBTUH	SC 33 Limit (lb/MMBTU)	Emissions lb/MMBTU
H-601	Process Heater	50.4	0.20	0.1
H-103	Process Heater	102.6	0.20	0.1
B-801	Boiler	72.5	0.20	0.1

OAC 252:100-35 (Carbon Monoxide) [Applicable]

Subchapter 35 requires new petroleum catalytic cracking and petroleum reforming units to reduce CO emissions by use of complete secondary combustion of the waste gas generated. Removal of 93 percent or more of the carbon monoxide generated is considered equivalent to secondary combustion. While this rule is not specific about compliance with the alternative standard for OAC 252:100-35, the intent of the regulation is to reduce emissions of CO to a level which is represented by complete combustion. Complete combustion of CO can be shown in other ways such as through operational parameters and exhaust gas CO concentrations. Based on average combustion processes, CO emissions from combustion units that are operating properly average 500 ppmv and range from 1,000 to 50 ppmv.

The Platformer CCR is considered a petroleum catalytic reforming unit and is also subject to this subchapter. Compliance with a CO limit of 100 ppmv in the exhaust gases from the regenerator should assure compliance with the intent of Subchapter 35. The modified permit will also include a requirement to determine the CO concentration in the exhaust gases from the Platformer CCR quarterly to show compliance with this emission limitation.

OAC 252:100-37 (Volatile Organic Compounds) [Applicable]
Part 1 requires all vapor-loss control devices, packing glands, and mechanical seals required by this subchapter to be properly installed, maintained, and operated.
Part 3 requires storage tanks constructed after December 28, 1974, with a capacity of 400 gallons or more and storing a VOC with a vapor pressure greater than 1.5 psia to be equipped with a permanent submerged fill pipe or with an organic vapor recovery system.
Part 3 requires storage tanks constructed after December 28, 1974, with a capacity of 40,000 gallons or more and storing a VOC with a vapor pressure greater than or equal to 1.5 psia to be a pressure vessel or to be equipped with an external floating roof or a fixed roof with an internal floating cover, or to be equipped with a vapor recovery system capable of collecting 85% of the uncontrolled VOC. The Oil-Water Separators are not storage tanks. The table below contains all tanks greater than 40,000 gallons that were constructed after December 28, 1974, and store a VOC with a vapor pressure greater than 1.5 psia. Tanks subject to the equipment standards of NSPS, Subparts K, Ka, or Kb are exempt from these requirements. All of these tanks were subject to NSPS, Subparts K and Ka and are not subject to this subchapter.

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1082	P-14	External Floating	Crude Oil	124,714	1974
T-1083	P-15	External Floating	Crude Oil	124,714	1974
T-1084	P-16	External Floating	Crude Oil	124,714	1978
T-1125	P-31	External Floating	Gasoline	124,405	1974
T-1126	P-32	External Floating	Gasoline	124,405	1974
T-1131	P-37	External Floating	Gasoline	125,095	1979
T-1132	P-38	External Floating	Reformate	80,143	1979

Part 7 requires all VOC gases from a vapor recovery blowdown system to be burned by a smokeless flare or equally effective control device unless it is inconsistent with the “Minimum Federal Safety Standards for the Transportation of Natural and Other Gas by Pipeline” or any State of Oklahoma regulatory agency. This facility flares all emissions that are not processed by a vapor recovery system.
Part 7 requires fuel-burning and refuse-burning equipment to be operated and maintained so as to minimize emissions of VOCs. Temperature and available air must be sufficient to provide essentially complete combustion. All equipment at the refinery is operated to minimize emissions of VOC.

Part 7 also requires all reciprocating pumps and compressors handling VOCs to be equipped with packing glands that are properly installed and maintained in good working order and rotating pumps and compressors handling VOCs to be equipped with mechanical seals. Equipment subject to NSPS, Subpart GGG are exempt from these requirements. The equipment affected by this permit at the refinery are subject to the requirements of NSPS, Subpart GGG and NESHAP, Subpart CC.

OAC 252:100-41 (Hazardous Air Pollutants and Toxic Air Contaminants) [Applicable]
Part 3 addresses hazardous air contaminants. NESHAP, as found in 40 CFR Part 61, are adopted by reference as they exist on July 1, 2003, with the exception of Subparts B, H, I, K, Q, R, T, W and Appendices D and E, all of which address radionuclides. In addition, General Provisions as found in 40 CFR Part 63, Subpart A, and the Maximum Achievable Control Technology (MACT) standards as found in 40 CFR Part 63, Subparts F, G, H, I, J, L, M, N, O, Q, R, S, T, U, W, X, Y, AA, BB, CC, DD, EE, GG, HH, II, JJ, KK, LL, MM, OO, PP, QQ, RR, SS, TT, UU, VV, WW, XX, YY, CCC, DDD, EEE, GGG, HHH, III, JJJ, LLL, MMM, NNN, OOO, PPP, QQQ, RRR, TTT, UUU, VVV, XXX, AAAA, CCCC, GGGG, HHHH, JJJJ, NNNN, OOOO, QQQQ, RRRR, SSSS, TTTT, UUUU, VVVV, WWWW, XXXX, BBBBB, CCCCC, FFFFF, JJJJJ, KKKKK, LLLLL, MMMMM, NNNNN, PPPPP, QQQQQ, and SSSSS are hereby adopted by reference as they exist on July 1, 2003. These standards apply to both existing and new sources of HAPs. These requirements are covered in the “Federal Regulations” section.
Part 5 is a **state-only** requirement governing toxic air contaminants. New sources (constructed after March 9, 1987) emitting any category “A” pollutant above de minimis levels must perform a BACT analysis, and if necessary, install BACT. All sources are required to demonstrate that emissions of any toxic air contaminant that exceeds the de minimis level do not cause or contribute to a violation of the MAAC. There are no toxic emissions from this project that will exceed the de minimis levels.

OAC 252:100-43 (Testing, Monitoring, and Recordkeeping) [Applicable]
This subchapter provides general requirements for testing, monitoring and recordkeeping and applies to any testing, monitoring or recordkeeping activity conducted at any stationary source. To determine compliance with emissions limitations or standards, the Air Quality Director may require the owner or operator of any source in the state of Oklahoma to install, maintain and operate monitoring equipment or to conduct tests, including stack tests, of the air contaminant source. All required testing must be conducted by methods approved by the Air Quality Director and under the direction of qualified personnel. A notice-of-intent to test and a testing protocol shall be submitted to Air Quality at least 30 days prior to any EPA Reference Method stack tests. Emissions and other data required to demonstrate compliance with any federal or state emission limit or standard, or any requirement set forth in a valid permit shall be recorded, maintained, and submitted as required by this subchapter, an applicable rule, or permit requirement. Data from any required testing or monitoring not conducted in accordance with the provisions of this subchapter shall be considered invalid. Nothing shall preclude the use, including the exclusive use, of any credible evidence or information relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

The following Oklahoma Air Pollution Control Rules are not applicable to this project:

OAC 252:100-7	Permit for Minor Facilities	not in source category
OAC 252:100-11	Alternative Emissions Reduction	not requested
OAC 252:100-15	Mobile Sources	not in source category
OAC 252:100-17	Incinerators	not type of EU
OAC 252:100-23	Cotton Gins	not type of EU
OAC 252:100-24	Grain Elevators	not in source category
OAC 252:100-39	Nonattainment Areas	not in area category
OAC 252:100-47	Existing Municipal Solid Waste Landfills	not in source category

SECTION VII. FEDERAL REGULATIONS

PSD, 40 CFR Part 52 [Applicable]
This facility is a PSD major source. Total potential emissions from this project exceed the SO_2 significance level of 40 TPY as shown in the "Emissions" section. The PSD requirements for this modification are addressed in the "PSD Review" section. Any future increases of emissions must be evaluated for PSD if they exceed a significance level.

NSPS, 40 CFR Part 60 [Subparts Dc, J, Kb, GGG, and QQQ are Applicable]
Subpart Dc, Small Industrial-Commercial-Institutional Steam Generating Units. This subpart affects steam generating units with a heat input capacity between 10 and 100 MMBTUH and that commences construction, modification, or reconstruction after June 9, 1989. Process heaters are not affected units. "Process heater" means a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst. Steam generating unit means a device that combusts any fuel and produces steam or heats water or any other heat transfer medium. EU SBH-002 is a hot oil heater and is considered a steam generating unit. The new hot oil heater is subject to the recordkeeping requirements of this subpart. All other heaters constructed after June 9, 1989, are considered process heaters.

EU	Description	MMBTUH	Const. Date
SBH-001	Hot Oil Heater	20.0	2004

Per 40 CFR 60.48(g) the owner/operator will be required to record and maintain records of the amounts of each fuel combusted during each day.

Subpart J, Petroleum Refineries. This subpart applies to the following affected facilities in petroleum refineries: FCCU catalyst regenerators, fuel gas combustion devices, and Claus sulfur recovery plants. This permit will not address any FCCU catalyst regenerators. The Platformer CCR is considered a catalytic reforming unit and is not subject to this subpart. All fuel gas combustion devices which commence construction or modification after June 11, 1973, are subject to a fuel gas H_2S limitation of 0.10 grains of H_2S/DSCF which is required to be continuously monitored and recorded. Fuel gas combusted by the affected units must be monitored and recorded and can be done at one location. Based on 1998 monitoring data, the typical sulfur content of the refinery fuel gas used at the Valero Refinery is 0.027 grains of

H_2S/DSCF. All fuel gas combustion devices subject to this subpart are listed below. All applicable emission limits, monitoring, and recordkeeping requirements for the refinery fuel gas combustion devices will be incorporated into the permit.

EU	Type of Unit	MMBTUH	Const. Date
H-601	Process Heater	50.4	1974
H-103	Process Heater	102.6	1974
H-301	Process Heater	22.5	1974
B-801	Boiler	72.5	1974
SBH-001	SRU Incinerator	40.4	2004
SBH-002	Hot Oil Heater	20.0	2004
H-6503	Co-Processor Heater	5.0	2004
H-302	Sat-Gas Debutanizer Reboiler	11.0	2004
H-402C	NHT Stripper Reboiler	20.0	2004
H-408	NHT Reactor Inter-Heater	12.0	2004

For Claus sulfur recovery plants with an oxidation control system or a reduction control system followed by incineration, Subpart J limits SO_2 emissions to 250 ppmvd at 0% excess air. The new SRU is subject to this emission limit, continuous emission monitoring, and the recordkeeping and reporting requirements of this subpart. All applicable requirements will be incorporated into the permit.

Subpart K, Storage Vessels for Petroleum Liquids. This subpart affects storage vessels for petroleum liquids which have a storage capacity greater than 40,000 gallons but less than 65,000 gallons and which commenced construction, reconstruction, or modification after March 8, 1974, or which have a capacity greater than 65,000 gallons which commenced construction, reconstruction, or modification after June 11, 1973, and prior to May 19, 1978.

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1008	P-1	Cone	LCO/Slurry	2,115	1975
T-1081	P-13	Cone	Diesel / Premium Diesel	79,917	1974
T-1082	P-14	External Floating	Crude Oil	124,714	1974
T-1083	P-15	External Floating	Crude Oil	124,714	1974
T-1102	P-19	Cone	Asphalt	77,000	1975
T-1113	P-22	Cone	Asphalt	131,283	1980
T-1125	P-31	External Floating	Gasoline	124,405	1974
T-1126	P-32	External Floating	Gasoline	124,405	1974
T-1127	P-33	Cone	Diesel / Jet Fuel	80,579	1974
T-1128	P-34	Cone	Diesel / Jet Fuel	80,636	1974
T-1129	P-35	Cone	Diesel / Jet Fuel	2,113	1975

Subpart Ka, Storage Vessels for Petroleum Liquids. This subpart affects storage vessels for petroleum liquids that have a storage capacity greater than 40,000 gallons and which commenced construction, reconstruction, or modification after May 18, 1978, and prior to July 23, 1984.

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1084	P-16	External Floating	Crude Oil	124,714	1978
T-1113	P-22	Cone	Asphalt	131,283	1980
T-1131	P-37	External Floating	Gasoline	125,095	1979
T-1132	P-38	External Floating	Reformate	80,143	1979

Subpart Kb, VOL Storage Vessels. This subpart affects storage vessels for VOL that has a storage capacity greater than 19,813 gallons and which commenced construction, reconstruction, or modification after July 23, 1984 except for the following:

- Tanks with a capacity greater than or equal to 39,890 gallons that store a liquid with a maximum true vapor pressure less than 0.5076 psia; or
- Tanks with a capacity greater than or equal to 19,813 but less than 39,890 gallons that store a liquid with a maximum true vapor pressure less than 2.1756 psia.

EU	Point	Roof Type	Contents	Barrels	Const. Date
V-8801	P-44	External Floating	Oil / Water	17,200	1993
V-8802	P-45	External Floating	Oil / Water	17,200	1993
T-84001	P-184	Cone	Sour Water	18,905	2005
T-1155	P-169	External Floating	Heavy Naphtha	164,000	2004
TK-AB001	P-172	Cone	Amine	895	2004
TK-SB001	P-171	Cone	Sulfur	3,300	2004

The definition of storage vessel under this subpart does not include process tanks which are defined as tanks that are used within a process (including a solvent or raw material recovery process) to collect material discharged from a feedstock storage vessel or equipment within the process before the material is transferred to other equipment within the process, to a product or by-product storage vessel, or to a vessel used to store recovered solvent or raw material. In many process tanks, unit operations such as reactions and blending are conducted. Other process tanks, such as surge control vessels and bottoms receivers, however, may not involve unit operations. The Oil-Water Separators are considered process tanks because they are used to separate the water and oil in the wastewater stream (a unit operation) and the recovered oil (a raw material) is then transferred to another tank for storage before being sent back through the refining process. The sour water and heavy naphtha tanks are not subject since they do not store a VOL with a vapor pressure greater than 0.5 psia. The amine and sulfur tanks do not store VOL.

Subpart VV, Equipment Leaks of VOC in the Synthetic Organic Manufacturing Industry. NSPS, Subpart GGG requires equipment in VOC service to comply with paragraphs §§ 60.482-1 through 60.482-10, 60.484, 60.485, 60.486, and 60.487 except as provided in § 60.593. All equipment in VOC service affected under this permit is subject to NSPS, Subpart GGG.

Subpart GGG, Equipment Leaks of VOC in Petroleum Refineries. This subpart affects each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service at a process unit, which commenced construction or modification after January 4, 1983, and which is located at a petroleum refinery. This subpart defines “process unit” as “components assembled to produce intermediate or final products from petroleum, unfinished petroleum derivatives, or other intermediates: a process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product.” Subpart GGG requires the leak detection, repair, and documentation procedures of NSPS, Subpart VV. All new affected equipment in VOC service and not in HAP service is subject to this subpart. After the effective date of 40 CFR Part 63 NESHAP, Subpart CC, (August 18, 1998), all equipment in organic HAP service is subject only to Subpart CC, which also requires compliance with NSPS, Subpart VV. The facility is required to comply with this subpart in Permit No. 98-172-C (M-12) (PSD). These requirements will also be incorporated into this permit.

Subpart LLL, Onshore Natural Gas Processing: SO_2 Emissions. This subpart affects each sweetening unit and each sweetening unit followed by a SRU that process natural gas which commenced construction or modification after January 20, 1984. Natural gas means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth’s surface. This facility only processes gases that are generated at the facility from the processing of crude oil.

Subpart QQQ, VOC Emission from Petroleum Refinery Wastewater Systems. This subpart applies to individual drain systems, oil-water separators, and aggregate facilities located in a petroleum refinery and which commenced construction, modification, or reconstruction after May 4, 1987. Drains are required to be equipped with water seal controls. Junction boxes are required to be equipped with a cover and may have an open vent pipe. Sewer lines shall not be open to the atmosphere and shall be covered or enclosed in a manner so as to have no visual gaps or cracks in joints, seals, or other emission interfaces. Oil-water wastewater separators shall be equipped with a fixed roof or a floating roof, which meets the required specifications. Group 1 wastewater streams that are managed under this subpart that are also subject to the provisions of NESHAP, Subpart CC are only required to comply with Subpart CC which requires compliance with NESHAP, Subpart FF. Subpart FF allows oil-water separators to comply with the requirements for alternative standards for oil-water separators of Subpart QQQ. This facility is subject to the requirements of NESHAP, Subpart CC. However, the Oil-Water Separators comply with the Alternative Standards for Oil-Water Separators of this subpart.

NESHAP, 40 CFR Part 61 [Subpart FF is Applicable]

Subpart J, Equipment Leaks (Fugitive Emission Sources) of Benzene. This subpart affects process streams that contain more than 10% benzene by weight. The maximum benzene concentration in any product stream at this site is 5% in super unleaded gasoline, and only trace amounts are expected in the refinery fuel gas.

Subpart FF, Benzene Waste Operations. This subpart affects benzene-contaminated wastewater at petroleum refineries. Facilities with 10 metric tons of benzene are required to manage and treat the waste streams. The permittee has elected to manage and treat the facility wastes such that the benzene quantity in the wastes is equal to or less than 6.0 metric tons per year.

NESHAP, Part 63, Subpart CC, requires all Group 1 wastewater streams to comply with §§ 61.340 through 61.355 of 40 CFR Part 61, Subpart FF, for each process wastewater stream that meets the definition in § 63.641. The facility is required to comply with this subpart in Permit No. 98-172-C (M-12) (PSD) and these requirements will also be incorporated into this permit.

NESHAP, 40 CFR Part 63 [Subparts CC and UUU are Applicable]
Subpart CC, Petroleum Refineries. This subpart, promulgated on August 18, 1995, affects the following process units and related emission points at petroleum refineries: miscellaneous process vents from petroleum refining process units, storage vessels associated with petroleum refining process units, wastewater streams and treatment operations associated with petroleum refining process units, and equipment leaks from petroleum refining process units; gasoline loading racks, marine vessel loading operations, and all storage vessels and equipment leaks associated with a bulk gasoline terminal or pipeline breakout station. The affected emission points are listed with a summary of applicable requirements.

Petroleum refining process units are defined as a process unit engaged in petroleum refining as defined in SIC code for petroleum refining and used primarily for the following:

- Producing transportation fuels (such as gasoline, diesel fuels, and jet fuels), heating fuels (such as kerosene, fuel gas distillate, and fuel oils), or lubricants;
- Separating petroleum; or
- Separating, cracking, reacting, or reforming intermediate petroleum streams.

Examples of such units include, but are not limited to, petroleum-based solvent units, alkylation units, catalytic hydrotreating, catalytic hydrorefining, catalytic hydrocracking, catalytic reforming, catalytic cracking, crude distillation, lube oil processing, hydrogen production, isomerization, polymerization, thermal processes, and blending, sweetening, and treating processes. Petroleum refining process units also include sulfur plants.

Miscellaneous process vents from petroleum refining process units
There are no Group 1 or 2 miscellaneous process vents affected by this permit.

Storage vessels associated with petroleum refining process units, bulk gasoline terminals, or pipeline breakout stations

Group 1 Tanks Affected By This Permit

EU	Point	Roof Type	Contents	Barrels
T-1135	P-8	Cone	Gasoline Blending	362
T-1082	P-14	External Floating	Crude Oil	124,714
T-1083	P-15	External Floating	Crude Oil	124,714
T-1084	P-16	External Floating	Crude Oil	124,714
T-1102	P-19	Cone	Asphalt	77,000
T-1151	P-189	Cone	Asphalt	176,395
T-1111	P-20	Cone	Asphalt / Fuel Oil	55,012
T-1112	P-21	Cone	Asphalt / Fuel Oil	10,100
T-1113	P-22	Cone	Asphalt	131,283
T-1123	P-29	External Floating	Gasoline	59,119
T-1124	P-30	External Floating	Gasoline	111,714
T-1125	P-31	External Floating	Gasoline	124,405
T-1126	P-32	External Floating	Gasoline	124,405
T-1131	P-37	External Floating	Gasoline	125,095
T-1132	P-38	External Floating	Reformate	80,143

Group 2 Tanks Affected By This Permit

EU	Point	Roof Type	Contents	Barrels
T-1008	P-1	Cone	LCO/Slurry	2,115
T-1118	P-6	Cone	Asphalt	35,000
T-1078	P-10	Cone	Heavy Naphtha	10,545
T-1079	P-11	Cone	Heavy Naphtha	9,948
T-1081	P-13	Cone	Diesel / Premium Diesel	79,917
T-1085	P-17	Cone	Slurry / #6 Fuel Oil	55,319
T-1102	P-19	Cone	Asphalt	77,000
T-1151	P-189	Cone	Asphalt	176,395
T-1111	P-20	Cone	Asphalt / Fuel Oil	55,012
T-1112	P-21	Cone	Asphalt / Fuel Oil	10,100
T-1113	P-22	Cone	Asphalt	131,283
T-1121	P-27	Cone	Diesel / Jet Fuel	40,526
T-1127	P-33	Cone	Diesel / Jet Fuel	80,579
T-1128	P-34	Cone	Diesel / Jet Fuel	80,636
T-1129	P-35	Cone	Diesel / Jet Fuel	2,113
V-818	P-43	Cone	Slop Oil	300
T-1155	P-169	External Floating	Heavy Naphtha	164,000

Group 1 and Group 2 storage vessels that are part of an existing source and subject to the provisions of NSPS, Subpart Kb are only required to comply with the provisions of NSPS, Subpart Kb except as provided in § 63.640(n)(8)(i) through (vi). Group 1 storage vessels that are part of an existing source and subject to the provisions of NSPS, Subparts K or Ka are only required to comply with this subpart. Group 2 storage vessels that are part of an existing source and that are subject to the provisions of NSPS, Subparts K or Ka are only required to comply with NSPS, Subparts K or Ka. Group 1 storage tanks not subject to NSPS, Subpart Kb are required to comply with the requirements of §§ 63.119 through 63.121 except as provided in § 63.646(b) through § 63.646(l). The owner or operator of these tanks are required to reduce HAP emissions to the atmosphere either by operating and maintaining a fixed roof and internal floating roof, an external floating roof, an external floating roof converted to an internal floating roof, or a closed vent system and control device, or routing the emissions to a process or a fuel gas system. The facility is also required to meet certain work practices and conduct inspections and maintain the tank seals similar to the requirements of NSPS, Subpart Kb.

<u>Wastewater streams and treatment operations associated with petroleum refining process units</u>
The wastewater streams and treatment operations associated with petroleum refining process units in organic HAP service are subject to this subpart and are required to comply with the requirements of this subpart. This subpart requires equipment that is used to manage a Group 1 wastewater stream to comply with the requirements of this subpart and 40 CFR §§ 61.340 through 61.355, NESHAP, Subpart FF. For Group 1 wastewater streams managed in a piece of equipment that is also subject to the provisions of NSPS, Subpart QQQ the equipment is only required to comply with the requirements of this subpart.

<u>Equipment leaks from petroleum refining process units, bulk gasoline terminals, or pipeline breakout stations</u>
All equipment in organic HAP service is required to comply with the provisions of 40 CFR Part 60, Subpart VV, except as provided in § 63.648(a)(1), (a)(2), and (c) through (i). All equipment subject to NSPS, Subpart GGG and this subpart is only required to comply with this subpart.

<u>Gasoline loading racks or pipeline breakout stations</u>
This permit will not address any gasoline loading racks or pipeline breakout stations.

<u>Marine vessel loading operations</u>
There are no marine vessel loading operations at this facility.

Catalytic cracking unit catalyst regeneration vents, catalytic reformer regeneration vents, sulfur recovery plant vents and fuel gas emission points are specifically exempted from this subpart. All applicable emission limits, work practices, monitoring, and recordkeeping requirements of this subpart will be incorporated into the permit.

Subpart UUU, Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and SRU. This subpart, affects the following EUs:

1. Catalytic cracking units that regenerate catalyst;
2. Catalytic reforming units that regenerate catalyst;
3. SRU and the TGTU serving it; and
4. Each bypass line serving a new, existing, or reconstructed catalytic cracking unit, catalytic reforming unit, or SRU.

This permit does not have any catalytic cracking units. Catalytic reforming units must comply with one of the organic HAP emission limits of § 63.1566(a)(1)(i) or (ii) during depressurizing and purging operations, the inorganic HAP emission limits of § 63.1567(a)(1)(i) or (ii) during coke burn off and catalyst regeneration, and all other applicable requirements. The Platformer CCR is a catalytic reforming unit and will be subject to the requirements of this subpart.

Sulfur recovery units subject to the NSPS, Subpart J, SO_2 emission limits must comply with the NSPS Subpart J, SO_2 emission limit. The SRU is subject to NSPS, Subpart J and will meet all applicable requirements of this subpart and NSPS, Subpart J.

Bypass lines must meet the work practice standards in Table 36 of this subpart.

All existing affected sources are required to comply with this subpart by April 11, 2005, except as provided by § 63.1563(c). All new or reconstructed affected sources are required to comply with this subpart upon startup. This subpart does not apply to thermal catalytic cracking units or gaseous streams routed to a fuel gas system. The SRU is considered a new source and the Platformer CCR is considered an existing source.

Subpart DDDDD, Industrial, Commercial and Institutional Boilers and Process Heaters. This subpart was promulgated on September 13, 2004. A new boiler or process heater is a boiler or process heater that commenced construction after January 13, 2003. Temporary boilers as defined in this subpart are not subject to this subpart. This subpart establishes emission limits and work practice standards for hazardous air pollutants (HAP) emitted from industrial, commercial, and institutional boilers and process heaters located at a major source of HAP. All of the boilers, heaters, and reboilers located at the refinery are in either the large gaseous fuel or small gaseous fuel subcategories. Small gaseous fuel units are units with a heat rating of less than or equal to 10 MMBTUH. Large gaseous fuel units are units with a heat rating greater than 10 MMBTUH.

Existing boilers and process heaters that are in the large gaseous fuels subcategory are only subject to the initial notification requirements. They are not subject to the emission limits, work practice standards, performance testing, monitoring, startup shutdown and maintenance plan, site-specific monitoring plans, recordkeeping and reporting requirements of this subpart or any other requirements in Subpart A. Existing and new boilers and process heaters in the small gaseous fuels subcategory are not subject to this subpart or the initial notification requirements.

This facility is a major source of HAP. The new boilers and process heaters in the large gaseous fuels subcategory are required to meet a CO emission limit of 400 ppmv on a dry basis corrected to three percent oxygen (30-day rolling average for units with a heat input of 100 MMBTUH or greater, 3-run average for units with a heat input of less than 100 MMBBTUH). New large gaseous fuel boilers and process heaters with a heat input less than 100 MMBTUH must conduct an initial performance test and annual performance tests thereafter to show compliance with the CO emission limit. New large gaseous fuel boilers and process heaters with a heat input rating greater than 100 MMBTUH must install continuous emission monitors. None of the new boilers or process heaters are rated greater than 100 MMBTUH. The facility must also develop a written start-up, shutdown, and malfunction plan and site-specific monitoring plan for each of the affected units. The boilers and process heaters subject to this subpart are shown below and are required to demonstrate compliance with this subpart within 180 days of operation including initial compliance testing.

EU	Description	MMBTUH	Const. Date
SBH-002	Hot Oil Heater	20.0	2004
H-302	Sat-Gas Debutanizer Reboiler	11.0	2004
H-402C	NHT Stripper Reboiler	20.0	2004
H-408	NHT Reactor Inter-Heater	12.0	2004

Air Quality reserves the right to reopen this permit if any other standard becomes applicable to this project.

CAM, 40 CFR Part 64 [Applicable]
Compliance Assurance Monitoring (CAM), as published in the Federal Register on October 22, 1997, applies to any pollutant specific EU at a major source, that is required to obtain a Title V permit, if it meets all of the following criteria:

1. It is subject to an emission limit or standard for an applicable regulated air pollutant;
2. It uses a control device to achieve compliance with the applicable emission limit or standard; and
3. It has potential emissions, prior to the control device, of the applicable regulated air pollutant greater than major source levels.

EUs subject to an emission limit or standard for which a Part 70 permit specifies a continuous compliance determination method are exempt from the CAM for that emission limit or standard. Emissions from the SRU are above the major source levels after control. However, the SRU will use a continuous emission monitor to ensure compliance with the limitation and is exempt from CAM.

The new WWTP is subject to emission limits and uses the WWTP Incinerator (a control device) to comply with the emission limitation, and has potential emissions greater than the major source threshold. Since the incinerator has potential emissions less than the major source levels after control, the permittee is not required to comply with CAM until the Title V renewal application. None of the other EUs meet the criteria stated above.

Chemical Accident Prevention Provisions, 40 CFR Part 68 [Applicable]
This facility handles naturally occurring hydrocarbon mixtures at a refinery and the Chemical Accident Prevention Provisions are applicable to this facility. The facility was required to submit the appropriate emergency response plan prior to June 21, 1999. The facility has submitted their plan which was given EPA No. 12005 for EPA Facility No. 1000 00128177. More information on this federal program is available on the web page: *www.epa.gov/ceppo*.

Stratospheric Ozone Protection, 40 CFR Part 82 [Subparts A and F are Applicable]
These standards require phase out of Class I & II substances, reductions of emissions of Class I & II substances to the lowest achievable level in all use sectors, and banning use of nonessential products containing ozone-depleting substances (Subparts A & C); control servicing of motor vehicle air conditioners (Subpart B); require Federal agencies to adopt procurement regulations which meet phase out requirements and which maximize the substitution of safe alternatives to Class I and Class II substances (Subpart D); require warning labels on products made with or containing Class I or II substances (Subpart E); maximize the use of recycling and recovery upon disposal (Subpart F); require producers to identify substitutes for ozone-depleting compounds under the Significant New Alternatives Program (Subpart G); and reduce the emissions of halons (Subpart H).
Subpart A identifies ozone-depleting substances and divides them into two classes. Class I controlled substances are divided into seven groups; the chemicals typically used by the manufacturing industry include carbon tetrachloride (Class I, Group IV) and methyl chloroform (Class I, Group V). A complete phase-out of production of Class I substances is required by January 1, 2000 (January 1, 2002, for methyl chloroform). Class II chemicals, which are hydrochlorofluorocarbons (HCFCs), are generally seen as interim substitutes for Class I CFCs. Class II substances consist of 33 HCFCs. A complete phase-out of Class II substances, scheduled in phases starting by 2002, is required by January 1, 2030.
Subpart F requires that any persons servicing, maintaining, or repairing appliances except for motor vehicle air conditioners; persons disposing of appliances, including motor vehicle air conditioners; refrigerant reclaimers, appliance owners, and manufacturers of appliances and recycling and recovery equipment comply with the standards for recycling and emissions reduction.

Conditions are included in the Standard Conditions of the permit to address the requirements specified at §82.156 for persons opening appliances for maintenance, service, repair, or disposal; §82.158 for equipment used during the maintenance, service, repair, or disposal of appliances; §82.161 for certification by an approved technician certification program of persons performing maintenance, service, repair, or disposal of appliances; §82.166 for recordkeeping; § 82.158 for leak repair requirements; and §82.166 for refrigerant purchase records for appliances normally containing 50 or more pounds of refrigerant.

SECTION VIII. TIER CLASSIFICATION, PUBLIC REVIEW, AND FEES

A. Tier Classification and Public Review for Modified PSD Permit

This permit has been determined to be a Tier II based on the request for a significant modification of a Tier II construction permit. The permittee has submitted an affidavit that they are not seeking a permit for land use or for any operation upon land owned by others without their knowledge. The affidavit certifies that the applicant owns the land used to accomplish the permitted purpose.

The applicant published the "Notice of Filing a Tier II Application" in the *Daily Ardmoreite*, a daily newspaper, in Carter County on August 25, 2004. The notice stated that the application was available for review at the Ardmore Public Library located at 320 E. NW, Ardmore, Oklahoma, the AQD main office. The applicant published the "Notice of Tier II Draft Permit" in the *Daily Ardmoreite*, a daily newspaper, in Carter County, on October 13, 2004. The notice stated that the draft permit was available for public review at the Ardmore Public Library located at 320 E. NW, Ardmore, Oklahoma, the AQD main office, and on the Air Quality section of the DEQ web page at *http://www.deq.state.ok.us*. This facility is located within 50 miles of the Oklahoma - Texas border. The state of Texas has been notified of the draft permit. The proposed permit was sent to EPA for a 45-day review period. No comments were received from the public, the state of Texas, or U.S. EPA Region VI.

B. Tier Classification and Public Review for Previous PSD Permit

The permit was determined to be a Tier II based on the request for a construction permit for an existing Part 70 source for a physical change that is considered significant under OAC 252:100-8-7.2(b)(2).

The applicant published the "Notice of Filing a Tier II Application" in the *Daily Ardmoreite*, a daily newspaper, in Carter County, on March 3, 2003. The notice stated that the application was available for public review at the Ardmore Public Library located at 320 E. NW, Ardmore, Oklahoma. The applicant published the "Notice of Tier II Draft Permit" in the *Daily Ardmoreite*, a daily newspaper, in Carter County, on May 27, 2003. The notice stated that the draft permit was available for public review at the Ardmore Public Library located at 320 E. NW, Ardmore, Oklahoma, the AQD main office and the Air Quality section of the DEQ web page at *http://www.deq.state.ok.us*. This facility is located within 50 miles of the Oklahoma - Texas border. The state of Texas has been notified of the draft permit. No comments were received from the public, the state of Texas, or EPA Region VI.

B. Fees Paid

Part 70 construction permit application fee of $1,500 for existing Part 70 sources.

SECTION IX. SUMMARY

The applicant has demonstrated the ability to comply with all applicable Air Quality rules and regulations. Ambient air quality standards are not threatened at this site. Compliance and Enforcement concur with the issuance of this permit. Issuance of the modified construction permit is recommended.

PERMIT TO CONSTRUCT
AIR POLLUTION CONTROL FACILITY
SPECIFIC CONDITIONS

Valero Energy Corporation **Permit No. 98-172-C (M-17) (PSD)**
TPI Petroleum, Inc.
Valero Ardmore Refinery

200 Long Ton per Day (LTPD) Sulfur Recovery Unit (SRU), 200 LTPD Tail Gas treating Unit (TGTU) and Amine Recovery Unit (ARU), and 100 Thousand Barrel per Day (MBPD) Crude Processing Rate Increase

The permittee is authorized to construct in conformity with the specifications submitted to Air Quality on January 23, 2003, October 6, 2003, June 24, 2004, and July 19, 2004 and all other supplemental materials. The Evaluation Memorandum dated November 22, 2004, explains the derivation of applicable permit requirements and estimates of emissions; however, it does not contain operating limitations or permit requirements. As required by applicable state and federal regulations, the permittee is authorized to construct, and/or operate, the affected equipment in conformity with the specifications contained herein. Commencing construction, or operations, under this permit constitutes acceptance of, and consent to, the conditions contained herein:

1. Upon issuance of an operating permit, the permittee shall be authorized to operate the affected facilities noted in this permit continuously (24 hours per day, every day of the year) subject to the following conditions: [OAC 252:100-8-6(a)(1)]

a. The Crude Unit shall not process fresh feedstock at a rate to exceed 100 thousand barrels per day (MBPD) based on a 12-month rolling average.
b. The Vacuum Unit shall not process fresh feedstock at a rate to exceed 34 MBPD based on a 12-month rolling average.
c. The polymer modified asphalt (PMA) unit shall not produce PMA at a rate to exceed 4,200,000 barrels per year (BPY) based on a 12-month rolling total.
d. The Catalytic Reforming/Platforming Unit shall not process fresh feedstock at a rate to exceed 26 MBPD based on a 12-month rolling average.
e. The Saturated Gas Plant unit shall not process fresh feedstock at a rate to exceed 16 MBPD based on a 12-month rolling average.
f. The Naphtha Hydrotreating (NHT) Unit shall not process fresh feedstock at a rate to exceed 33 MBPD based on a 12-month rolling average.
g. The SRU shall not process more than 130 long tons per day (LTPD) of sulfur based on a 12-month rolling average without oxygen enrichment.
h. The SRU shall not process more than 200 tons per day (TPD) of sulfur based on a 12-month rolling average with oxygen enrichment.
i. The permittee shall determine and record the throughputs of the Crude Unit, Vacuum Unit, Catalytic Reforming/Platforming Unit, Saturated Gas Plant, and NHT Unit (daily) and the amount of sulfur processed through the SRU (daily) and whether it is being operated with or without oxygen enrichment.

j. To determine compliance with the limits stated above the permittee shall average the daily throughputs recorded during a calendar month and then determine the 12-month rolling average using the monthly average of daily throughputs.

2. Emission limitations and standards for affected Emission Units (EU):

EUG 1 Storage Tank T-1008. Emissions from EU T-1008 are based on a throughput of 2,275,243 BPY and are considered insignificant (<5 TPY).

EU	Point	Roof Type	Contents	Barrels
T-1008	P-1	Cone	LCO/Slurry	2,115

a. The permittee shall comply with the applicable sections of National Emission Standards for Hazardous Air Pollutants (NESHAP), 40 CFR Part 63, Subpart CC for the affected tank.
   i. §63.642 General Standards
   ii. §63.646 Storage Vessel Provisions
   iii. §63.654 Reporting and Recordkeeping Requirements
b. The tank shall not store a VOC with a maximum vapor pressure greater than 0.01 psia under actual storage conditions.
c. The throughput for EU T-1008 shall not exceed 2,275,243 BPY based on a 12-month rolling total. [OAC 252:100-8-6(a)(1)]
d. The permittee shall record the throughput of the tank (monthly) and determine and record the true vapor pressure of the material stored in the tank (quarterly). [OAC 252:100-8-6(a)(3)]

EUG 6 Storage Tank T-1118. There are no emission limits established for EU T-1118 since this tank is grandfathered, except to comply with the NESHAP, Subpart CC, but it is limited to the existing equipment as it is.

EU	Point	Roof Type	Contents	Barrels
T-1118	P-6	Cone	Asphalt	35,000

a. The permittee shall comply with the applicable sections of NESHAP, 40 CFR Part 63, Subpart CC for the affected tank.
   i. §63.642 General Standards
   ii. §63.646 Storage Vessel Provisions
   iii. §63.654 Reporting and Recordkeeping Requirements

EUG 8 Storage Tank T-1135. There are no emission limits established for EU T-1135 since this tank is grandfathered, except to comply with the NESHAP, Subpart CC, but it is limited to the existing equipment as it is.

EU	Point	Roof Type	Contents	Barrels
T-1135	P-8	Cone	Gasoline Blending	362

a. The permittee shall comply with the applicable sections of NESHAP, 40 CFR Part 63, Subpart CC for the affected tank.
   i. §63.642 General Standards
   ii. §63.646 Storage Vessel Provisions
   iii. §63.654 Reporting and Recordkeeping Requirements

EUG 10 Storage Tank T-1078 shall be blinded off and dismantled.

EU	Point	Roof Type	Contents	Barrels
T-1078	P-10	Cone	Heavy Naphtha	10,545

EUG 11 Storage Tank T-1079 shall be blinded off and dismantled.

EU	Point	Roof Type	Contents	Barrels
T-1079	P-11	Cone	Heavy Naphtha	9,948

EUG 13 Storage Tank T-1081. Emissions from EU T-1081 are based on a throughput of 1,822,982 BPY and are considered insignificant (<5 TPY).

EU	Point	Roof Type	Contents	Barrels
T-1081	P-13	Cone	Diesel / Premium Diesel	79,917

a. The permittee shall comply with the applicable sections of NESHAP, 40 CFR Part 63, Subpart CC for the affected tank.
   i. §63.642 General Standards
   ii. §63.646 Storage Vessel Provisions
   iii. §63.654 Reporting and Recordkeeping Requirements
b. The tank shall not store a VOC with a maximum vapor pressure greater than 0.05 psia under actual storage conditions.
c. The throughput for EU T-1081 shall not exceed 1,822,982 BPY based on a 12-month rolling total. [OAC 252:100-8-6(a)(1)]
d. The permittee shall record the throughput of the tank (monthly) and determine and record the true vapor pressure of the material stored in the tank (quarterly). [OAC 252:100-8-6(a)(3)]

EUG 14, 15, & 16 Storage Tanks T-1082, T-1083, and T-1084, respectively. The emission limit for EU T-1082, T-1083, and T-1084 is based on a total throughput of 100 thousand barrels per day (MBPD).

EU	Point	Roof Type	Contents	Barrels
T-1082	P-14	External Floating	Crude Oil	124,714
T-1083	P-15	External Floating	Crude Oil	124,714
T-1084	P-16	External Floating	Crude Oil	124,714

VOC
TPY
11.3

a. The permittee shall comply with the applicable sections of NESHAP, 40 CFR Part 63, Subpart CC for the affected tanks.
   i. §63.642 General Standards
   ii. §63.646 Storage Vessel Provisions
   iii. §63.654 Reporting and Recordkeeping Requirements
b. The tanks shall not store a VOC with a maximum vapor pressure greater than 11.0 psia under actual storage conditions.
c. The total throughput for EU T-1082, T-1083, and T-1084 shall not exceed 100 MBPD based on a 12-month rolling average. [OAC 252:100-8-6(a)(1)]
d. The permittee shall record the throughput of the tanks (monthly) and determine and record the true vapor pressure of the material stored in the tanks (quarterly). [OAC 252:100-8-6(a)(3)]
e. Compliance with the emission limitation shall be based on the tank throughputs and the most recent version of EPA Tanks program. Compliance with the TPY limit shall be based on a 12-month rolling total.

EUG 17 Storage Tank T-1085. There are no emission limits established for EU T-1085 since this tank is grandfathered, except to comply with the NESHAP, Subpart CC, but it is limited to the existing equipment as it is.

EU	Point	Roof Type	Contents	Barrels
T-1085	P-17	Cone	Slurry / #6 Fuel Oil	55,319

a. The permittee shall comply with the applicable sections of NESHAP, 40 CFR Part 63, Subpart CC for the affected tank.
   i. §63.642 General Standards
   ii. §63.646 Storage Vessel Provisions
   iii. §63.654 Reporting and Recordkeeping Requirements

EUG 19 Storage Tanks T-1102 and T-1151. Emissions from EU T-1102 are based on a throughput of 688,240 BPY and are considered insignificant (<5 TPY). There are no emission limits established for EU T-1151 since this tank is grandfathered, except to comply with the NESHAP, Subpart CC, but it is limited to the existing equipment as it is.

EU	Point	Roof Type	Contents	Barrels
T-1102	P-19	Cone	Asphalt	77,000
T-1151	P-189	Cone	Asphalt	176,395

a. The permittee shall comply with the applicable sections of NESHAP, 40 CFR Part 63, Subpart CC for the affected tanks.
   i. §63.642 General Standards
   ii. §63.646 Storage Vessel Provisions
   iii. §63.654 Reporting and Recordkeeping Requirements
b. EU T-1102 shall not store a VOC with a maximum vapor pressure greater than 0.05 psia under actual storage conditions.
c. The throughput for EU T-1102 shall not exceed 688,240 BPY based on a 12-month rolling total. [OAC 252:100-8-6(a)(1)]
d. The permittee shall record the throughput of the EU T-1102 (monthly) and determine and record the true vapor pressure of the material stored in EU T-1102 (quarterly). [OAC 252:100-8-6(a)(3)]

EUG 20 Storage Tank T-1111 and T-1112. There are no emission limits established for EU T-1111 and T-1112 since these tanks are grandfathered, except to comply with the NESHAP, Subpart CC, but they are limited to the existing equipment as it is.

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1111	P-20	Cone	Asphalt / Fuel Oil	55,012	1954
T-1112	P-21	Cone	Asphalt / Fuel Oil	10,100	1954

a. The permittee shall comply with the applicable sections of NESHAP, 40 CFR Part 63, Subpart CC for the affected tanks.
   i. §63.642 General Standards
   ii. §63.646 Storage Vessel Provisions
   iii. §63.654 Reporting and Recordkeeping Requirements

EUG 21 Storage Tank T-1113. Emissions from EU T-1113 are based on a throughput of 1,200,548 BPY and are considered insignificant (<5 TPY).

EU	Point	Roof Type	Contents	Barrels
T-1113	P-22	Cone	Asphalt	131,283

a. The permittee shall comply with the applicable sections of NESHAP, 40 CFR Part 63, Subpart CC for the affected tank.
   i. §63.642 General Standards
   ii. §63.646 Storage Vessel Provisions
   iii. §63.654 Reporting and Recordkeeping Requirements
b. The tank shall not store a VOC with a maximum vapor pressure greater than 0.05 psia under actual storage conditions.
c. The throughput for EU T-1113 shall not exceed 1,200,548 BPY based on a 12-month rolling total. [OAC 252:100-8-6(a)(1)]
d. The permittee shall record the throughput of the tank (monthly) and determine and record the true vapor pressure of the material stored in the tank (quarterly). [OAC 252:100-8-6(a)(3)]

EUG 24 Storage Tank T-1121. There are no emission limits established for EU T-1121 since this tank is grandfathered, except to comply with the NESHAP, Subpart CC, but it is limited to the existing equipment as it is.

EU	Point	Roof Type	Contents	Barrels
T-1121	P-27	Cone	Diesel / Jet Fuel	40,526

a. The permittee shall comply with the applicable sections of NESHAP, 40 CFR Part 63, Subpart CC for the affected tank.
   i. §63.642 General Standards
   ii. §63.646 Storage Vessel Provisions
   iii. §63.654 Reporting and Recordkeeping Requirements

EUG 26 Storage Tank T-1123. There are no emission limits established for EU T-1123 since this tank is grandfathered, except to comply with the NESHAP, Subpart CC, but it is limited to the existing equipment as it is.

EU	Point	Roof Type	Contents	Barrels
T-1123	P-29	External Floating	Gasoline	59,119

a. The permittee shall comply with the applicable sections of NESHAP, 40 CFR Part 63, Subpart CC for the affected tank.
   i. §63.642 General Standards
   ii. §63.646 Storage Vessel Provisions
   iii. §63.654 Reporting and Recordkeeping Requirements

EUG 27 Storage Tank T-1124. There are no emission limits established for EU T-1124 since this tank is grandfathered, except to comply with the NESHAP, Subpart CC, but it is limited to the existing equipment as it is.

EU	Point	Roof Type	Contents	Barrels
T-1124	P-30	External Floating	Gasoline	111,714

a. The permittee shall comply with the applicable sections of NESHAP, 40 CFR Part 63, Subpart CC for the affected tank.
   i. §63.642 General Standards
   ii. §63.646 Storage Vessel Provisions
   iii. §63.654 Reporting and Recordkeeping Requirements

EUG 28 Storage Tank T-1125. The emission limit for EU T-1125 is based on a throughput of 7,500,000 BPY.

EU	Point	Roof Type	Contents	Barrels
T-1125	P-31	External Floating	Gasoline	124,405

VOC
TPY
12.0

a. The permittee shall comply with the applicable sections of NESHAP, 40 CFR Part 63, Subpart CC for the affected tank.
   i. §63.642 General Standards
   ii. §63.646 Storage Vessel Provisions
   iii. §63.654 Reporting and Recordkeeping Requirements
b. The tank shall not store a VOC with a maximum vapor pressure greater than 11.0 psia under actual storage conditions.
c. The throughput for EU T-1125 shall not exceed 7,500,000 BPY based on a 12-month rolling total. [OAC 252:100-8-6(a)(1)]
d. The permittee shall record the throughput of the tank (monthly) and determine and record the true vapor pressure of the material stored in the tank (quarterly). [OAC 252:100-8-6(a)(3)]
e. Compliance with the emission limitation shall be based on the tank throughputs and the most recent version of EPA Tanks program. Compliance with the TPY limit shall be based on a 12-month rolling total.

EUG 29 Storage Tank T-1126. The emission limit for EU T-1126 is based on a throughput of 7,500,000 BPY.

EU	Point	Roof Type	Contents	Barrels
T-1126	P-32	External Floating	Gasoline	124,405

VOC
TPY
12.0

a. The permittee shall comply with the applicable sections of NESHAP, 40 CFR Part 63, Subpart CC for the affected tank.
   i. §63.642 General Standards
   ii. §63.646 Storage Vessel Provisions
   iii. §63.654 Reporting and Recordkeeping Requirements
b. The tank shall not store a VOC with a maximum vapor pressure greater than 11.0 psia under actual storage conditions.
c. The throughput for EU T-1126 shall not exceed 7,500,000 BPY based on a 12-month rolling total. [OAC 252:100-8-6(a)(1)]
d. The permittee shall record the throughput of the tank (monthly) and determine and record the true vapor pressure of the material stored in the tank (quarterly). [OAC 252:100-8-6(a)(3)]
e. Compliance with the emission limitation shall be based on the tank throughputs and the most recent version of EPA Tanks program. Compliance with the TPY limit shall be based on a 12-month rolling total.

EUG 30 Storage Tank T-1127. Emissions from EU T-1127 are based on a throughput of 3,300,000 BPY and are considered insignificant (<5 TPY).

EU	Point	Roof Type	Contents	Barrels
T-1127	P-33	Cone	Diesel / Jet Fuel	80,579

a. The permittee shall comply with the applicable sections of NESHAP, 40 CFR Part 63, Subpart CC for the affected tank.
   i. §63.642 General Standards
   ii. §63.646 Storage Vessel Provisions
   iii. §63.654 Reporting and Recordkeeping Requirements
b. The tank shall not store a VOC with a maximum vapor pressure greater than 0.05 psia under actual storage conditions.
c. The throughput for EU T-1127 shall not exceed 3,300,000 BPY based on a 12-month rolling total. [OAC 252:100-8-6(a)(1)]
d. The permittee shall record the throughput of the tank (monthly) and determine and record the true vapor pressure of the material stored in the tank (quarterly). [OAC 252:100-8-6(a)(3)]

EUG 31 Storage Tank T-1128. Emissions from EU T-1128 are based on a throughput of 3,300,000 BPY and are considered insignificant (<5 TPY).

EU	Point	Roof Type	Contents	Barrels
T-1128	P-34	Cone	Diesel / Jet Fuel	80,636

a. The permittee shall comply with the applicable sections of NESHAP, 40 CFR Part 63, Subpart CC for the affected tank.
   i. §63.642 General Standards
   ii. §63.646 Storage Vessel Provisions
   iii. §63.654 Reporting and Recordkeeping Requirements
b. The tank shall not store a VOC with a maximum vapor pressure greater than 0.05 psia under actual storage conditions.
c. The throughput for EU T-1128 shall not exceed 3,300,000 BPY based on a 12-month rolling total. [OAC 252:100-8-6(a)(1)]
d. The permittee shall record the throughput of the tank (monthly) and determine and record the true vapor pressure of the material stored in the tank (quarterly). [OAC 252:100-8-6(a)(3)]

EUG 32 Storage Tank T-1129. Emissions from EU T-1129 are based on a throughput of 61,264 BPY and are considered insignificant (<5 TPY).

EU	Point	Roof Type	Contents	Barrels
T-1129	P-35	Cone	Diesel / Jet Fuel	2,113

a. The permittee shall comply with the applicable sections of NESHAP, 40 CFR Part 63, Subpart CC for the affected tank.
   i. §63.642 General Standards
   ii. §63.646 Storage Vessel Provisions
   iii. §63.654 Reporting and Recordkeeping Requirements
b. The tank shall not store a VOC with a maximum vapor pressure greater than 0.05 psia under actual storage conditions.
c. The throughput for EU T-1129 shall not exceed 61,264 BPY based on a 12-month rolling total. [OAC 252:100-8-6(a)(1)]
d. The permittee shall record the throughput of the tank (monthly) and determine and record the true vapor pressure of the material stored in the tank (quarterly). [OAC 252:100-8-6(a)(3)]

EUG 34 Storage Tank T-1131. The emission limit for EU T-1131 is based on a throughput of 7,884,000 BPY.

EU	Point	Roof Type	Contents	Barrels
T-1131	P-37	External Floating	Gasoline	125,095

VOC
TPY
9.7

a. The permittee shall comply with the applicable sections of NESHAP, 40 CFR Part 63, Subpart CC for the affected tank.
   i. §63.642 General Standards
   ii. §63.646 Storage Vessel Provisions
   iii. §63.654 Reporting and Recordkeeping Requirements
b. The tank shall not store a VOC with a maximum vapor pressure greater than 9.0 RVP under actual storage conditions.
c. The throughput for EU T-1131 shall not exceed 7,884,000 BPY based on a 12-month rolling total. [OAC 252:100-8-6(a)(1)]
d. The permittee shall record the throughput of the tank (monthly) and determine and record the true vapor pressure of the material stored in the tank (quarterly). [OAC 252:100-8-6(a)(3)]
e. Compliance with the emission limitation shall be based on the tank throughputs and the most recent version of EPA Tanks program. Compliance with the TPY limit shall be based on a 12-month rolling total.

EUG 35 Storage Tank T-1132. Emissions from EU T-1132 are based on a throughput of 9,490,000 BPY and are considered insignificant (<5 TPY).

EU	Point	Roof Type	Contents	Barrels
T-1132	P-38	External Floating	Reformate	80,143

a. The permittee shall comply with the applicable sections of NESHAP, 40 CFR Part 63, Subpart CC for the affected tank.
   i. §63.642 General Standards
   ii. §63.646 Storage Vessel Provisions
   iii. §63.654 Reporting and Recordkeeping Requirements
b. The tank shall not store a VOC with a maximum vapor pressure greater than 5.0 RVP under actual storage conditions.
c. The throughput for EU T-1132 shall not exceed 9,490,000 BPY based on a 12-month rolling total. [OAC 252:100-8-6(a)(1)]
d. The permittee shall record the throughput of the tank (monthly) and determine and record the true vapor pressure of the material stored in the tank (quarterly). [OAC 252:100-8-6(a)(3)]

EUG 40 Storage Tank V-818. There are no emission limits established for EU V-818 since this tank is grandfathered, except to comply with the NESHAP, Subpart CC, but it is limited to the existing equipment as it is.

EU	Point	Roof Type	Contents	Barrels
V-818	P-43	Cone	Slop Oil	300

a. The permittee shall comply with the applicable sections of NESHAP, 40 CFR Part 63, Subpart CC for the affected tank.
   i. §63.642 General Standards
   ii. §63.646 Storage Vessel Provisions
   iii. §63.654 Reporting and Recordkeeping Requirements

EUG 41 Oil-Water Separators V-8801 & V-8802. The emission limit for EU V-8801 &V-8802 is based on a throughput of 9,560,914 BPY.

EU	Point	Roof Type	Contents	Barrels
V-8801	P-44	External Floating	Oil / Water	17,200
V-8802	P-45	External Floating	Oil / Water	17,200

VOC
TPY
7.3

a. The permittee shall comply with the applicable sections of NESHAP, 40 CFR Part 63, Subpart CC, Wastewater Provisions of § 63.647 for the Oil-Water Separators (V-8801 and V-8802). [40 CFR 63.640-654]
   i. The permittee shall comply with the requirements of § 61.340 through § 61.355 of 40 CFR Part 61, Subpart FF. [§ 63.647(a)]
      A. The Oil-Water Separators (V-8801 and V-8802) shall comply with the Alternative Standards for Oil-Water Separators of 40 CFR § 61.352 and § 60.693-2(a).

b. The tank shall not store a VOC with a maximum vapor pressure greater than 11.0 psia under actual storage conditions.
c. The total throughput of EU V-8801 & V-8802 shall not exceed 9,560,914 BPY based on a 12-month rolling total. [OAC 252:100-8-6(a)(1)]
d. The permittee shall record the throughput of the tanks (monthly) and determine and record the true vapor pressure of the material stored in the tanks (quarterly). [OAC 252:100-8-6(a)(3)]
e. The cover shall rest on the surface of the contents and be equipped with a closure seal, or seals, to close the space between the cover edge and container wall. All gauging and sampling devices shall be gas-tight except when gauging or sampling is taking place. The oil removal devices shall be gas-tight except when manual skimming, inspection and/or repair is in progress. [OAC 252:100-37-37(2)]
f. Compliance with the emission limitation shall be based on the tank throughputs and the most recent version of WATER9 program. Compliance with the TPY limit shall be based on a 12-month rolling total.

EUG 48 Sour Water Stripper Tank (T-1152). Emissions from EU T-1152 are based on a throughput of 2,131,286 BPY and operation of the tank with a barrier of diesel fluid at least six inches thick and are considered insignificant (<5 TPY).

EU	Point	Roof Type	Contents	Barrels
T-1152	P-55	Cone	Sour Water	10,424

a. The permittee shall comply with the applicable sections of NESHAP, 40 CFR Part 63, Subpart CC for the affected tank.
   i. §63.642 General Standards
   ii. §63.646 Storage Vessel Provisions
   iii. §63.654 Reporting and Recordkeeping Requirements
b. EU T-1152 shall be operated with a barrier of diesel fluid. [OAC 252:100-8-6(a)(1)]
c. The throughput for EU T-1152 shall not exceed 2,131,286 BPY based on a 12-month rolling total. [OAC 252:100-8-6(a)(1)]
d. The permittee shall record the throughput of the tank (monthly). [OAC 252:100-8-6(a)(3)]

EUG 49 Sour Water Stripper Tank (T-84001). Emissions from EU T-84001 are based on a throughput of 2,502,857 BPY and operation of the tank with a barrier of diesel fluid at least six inches thick and are considered insignificant (<5 TPY).

EU	Point	Roof Type	Contents	Barrels
T-84001	P-184	Cone	Sour Water	

a. The permittee shall comply with the applicable sections of NESHAP, 40 CFR Part 63, Subpart CC for the affected tank.
   i. §63.642 General Standards
   ii. §63.646 Storage Vessel Provisions
   iii. §63.654 Reporting and Recordkeeping Requirements

b. EU T-84001 shall be operated with a barrier of diesel fluid. [OAC 252:100-8-6(a)(1)]

c. The throughput for EU T-84001 shall not exceed 2,502,857 BPY based on a 12-month rolling total. [OAC 252:100-8-6(a)(1)]

d. The permittee shall record the throughput of the tank (monthly). [OAC 252:100-8-6(a)(3)]

EUG 107 Process Heater (H-601). Emission limits and standards for EU H-601 are listed below. Emissions from H-601 are based on a maximum rated capacity (HHV) of 50.4 MMBTUH, the respective emissions factors from AP-42, Section 1.4 (7/98), and a fuel gas hydrogen sulfide (H_2S) concentration of 159 ppmdv.

EU	Point	Description	MMBTUH
H-601	P-108	Process Heater	50.4

NO_X		CO		SO_2	
lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
5.7	25.1	4.8	21.1	2.0	8.6

a. EU H-601 is subject to NSPS, Subpart J and shall comply with all applicable provisions. [40 CFR Part 60, Subpart J]
   i. § 60.104 Standards for sulfur dioxide – (a)(1)
   ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii)
   iii. § 60.106 Test methods and procedures – (e)

b. EU H-601 shall only be fired with refinery fuel gas. [OAC 252:100-8-6(a)(1)]

c. Fuel use (SCF) and heat content (BTU/SCF) for EU H-601 shall be monitored and recorded (monthly). [OAC 252:100-8-6(a)(3)]

d. Compliance with the emission limitations shall be based on the fuel consumption, fuel heat content, and the emission factors used to calculate emissions indicated above. Compliance with the TPY limits shall be based on a 12-month rolling total.

EUG 109 Process Heater (H-901). There are no emission limits established for EU H-901 since this tank is grandfathered but it is limited to the existing equipment as it is. Emissions from H-901 are based on a maximum rated capacity (HHV) of 51.9 MMBTUH, the respective emissions factors from AP-42, Section 1.4 (7/98), and a fuel gas hydrogen sulfide (H_2S) concentration of 159 ppmdv.

EU	Point	Description	MMBTUH
H-901	P-110	Process Heater	51.9

EUG 117 Process Heater (H-103). Emission limits and standards for EU H-103 are listed below. Emissions from H-103 are based on a maximum rated capacity (HHV) of 102.6 MMBTUH, the respective emissions factors from AP-42, Section 1.4 (7/98), and a fuel gas hydrogen sulfide (H_2S) concentration of 159 ppmdv.

EU	Point	Description	MMBTUH
H-103	P-118	Process Heater	102.6

NO_X		CO		SO_2	
lb/hr	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
10.1	44.1	8.5	37.0	3.5	15.1

a. EU H-103 is subject to NSPS, Subpart J and shall comply with all applicable provisions. [40 CFR Part 60, Subpart J]
   i. § 60.104 Standards for sulfur dioxide – (a)(1)
   ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii)
   iii. § 60.106 Test methods and procedures – (e)

b. EU H-103 shall only be fired with refinery fuel gas. [OAC 252:100-8-6(a)(1)]

c. Fuel use (SCF) and heat content (BTU/SCF) for EU H-103 shall be monitored and recorded (monthly). [OAC 252:100-8-6(a)(3)]

d. Compliance with the emission limitations shall be based on the fuel consumption, fuel heat content, and the emission factors used to calculate emissions indicated above. Compliance with the TPY limits shall be based on a 12-month rolling total.

EUG 119 Process Heater (H-301). Emission limits and standards for EU H-301 are listed below. Emissions from H-301 are based on a maximum rated capacity (HHV) of 22.5 MMBTUH, the respective emissions factors from AP-42, Section 1.4 (7/98), and a fuel gas hydrogen sulfide (H_2S) concentration of 159 ppmdv.

EU	Point	Description	MMBTUH
H-301	P-120	Process Heater	22.5

NO_X		CO		SO_2	
lb/hr	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
2.1	9.3	1.8	7.8	0.7	3.2

a. EU H-301 is subject to NSPS, Subpart J and shall comply with all applicable provisions. [40 CFR Part 60, Subpart J]
   i. § 60.104 Standards for sulfur dioxide – (a)(1)
   ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii)
   iii. § 60.106 Test methods and procedures – (e)

b. EU H-301 shall only be fired with refinery fuel gas. [OAC 252:100-8-6(a)(1)]

c. Fuel use (SCF) and heat content (BTU/SCF) for EU H-301 shall be monitored and recorded (monthly). [OAC 252:100-8-6(a)(3)]

d. Compliance with the emission limitations shall be based on the fuel consumption, fuel heat content, and the emission factors used to calculate emissions indicated above. Compliance with the TPY limits shall be based on a 12-month rolling total.

EUG 125 Boiler (B-801). Emission limits and standards for EU B-801 are listed below. Emissions from B-801 are based on a maximum rated capacity (HHV) of 72.5 MMBTUH, the respective emissions factors from AP-42, Section 1.4 (7/98), and a fuel gas hydrogen sulfide (H_2S) concentration of 159 ppmdv.

EU	Point	Description	MMBTUH
B-801	P-126	Boiler	72.5

NO_X		CO		SO_2	
lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
7.1	31.1	6.0	26.2	2.4	10.7

a. EU B-801 is subject to NSPS, Subpart J and shall comply with all applicable provisions. [40 CFR Part 60, Subpart J]

   i. § 60.104 Standards for sulfur dioxide – (a)(1)
   ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii)
   iii. § 60.106 Test methods and procedures – (e)

b. EU B-801 shall only be fired with refinery fuel gas. [OAC 252:100-8-6(a)(1)]

c. Fuel use (SCF) and heat content (BTU/SCF) for EU H-801 shall be monitored and recorded (monthly). [OAC 252:100-8-6(a)(3)]

d. Compliance with the emission limitations shall be based on the fuel consumption, fuel heat content, and the emission factors used to calculate emissions indicated above. Compliance with the TPY limits shall be based on a 12-month rolling total.

EUG 146 Platformer Catalyst Regeneration Vent (CCR). Emission limits and standards for EU CCR are listed below. Emissions from the CCR are based on a coke-burning rate of 70 lbs/hr, which is equivalent to a maximum catalyst recirculation rate of 1,000 lb/hr and a coke combustion rate of 7% of the catalyst processing rate (1,000 lb/hr @ 7% wt), with a coke maximum sulfur content of 0.5% by weight. Coke combustion emissions were based on the following emissions factors from AP-42 (1/95), Section 1.1, for sub-bituminous coal combustion: NO_X - 34 lb/ton of coke combusted (Pulverized coal fired, wet bottom); CO - 5 lb/ton of coke combusted (Spreader Stoker); PM_{10} - 13.2 lb/ton of coke combusted (Spreader Stoker) & 0.07 lb/hr catalyst; SO_2 - 38 x (Sulfur Content) lb/ton of coke combusted (Spreader Stoker); VOC - 1.3 lb/ton of coke combusted (Underfeed Stoker). PM_{10} emissions also include a recovery factor for the catalyst of 99.99%.

EU	Point	Description
CCR	P-150	Platformer Catalyst Regeneration Combustion Vent

NO_X		CO		PM_{10}		SO_2	
lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
1.2	5.2	0.2	0.8	0.6	2.5	0.7	2.9

a. The catalyst recirculation rate shall not exceed 1,000 lb/hr. [OAC 252:100-8-6(a)(1)]

b. The CCR shall be operated in full combustion regeneration mode to reduce emissions of CO to at least 100 ppmv. [OAC 252:100-35-2(b)]
   i. At least once per calendar quarter, the permittee shall conduct tests of CO concentrations in the exhaust gases from the CCR when operating under representative conditions. Testing shall be conducted using a portable analyzer or an equivalent method approved by Air Quality. When four consecutive quarterly tests show compliance with the CO emissions limitation, the testing frequency may be reduced to semi-annual testing.
c. The sulfur content of the Platformer feed shall not exceed 5% by weight based on a 12-month rolling average. [OAC 252:100-8-6(a)(1)]
d. The permittee shall not use more than 85,762 lb/yr of chloride (Cl) based on a 12-month rolling total.
e. The permittee shall determine and record sulfur content of the CCR Feed (monthly) and the chloride usage of the CCR (monthly). [OAC 252:100-8-6(a)(3)]
f. Compliance with the emission limitations shall be based on the average monthly catalyst recirculation rate and the emission factors used to calculate emissions indicated above. Compliance with the TPY limits shall be based on a 12-month rolling total.
g. The CCR is subject to NESHAP, 40 CFR Part 63, Subpart UUU and shall comply with all applicable requirements by the dates specified in §63.1563(b).
[40 CFR 63, NESHAP, Subpart UUU]
h. The limits of Permit No. 98-172-C (M-15) (PSD) for this EU are superceded by this permit.

EUG 169 Storage Tank T-1155. Emissions from EU T-1155 are based on a throughput of 12,045,000 BPY and are considered insignificant (<5 TPY).

EU	Point	Roof Type	Contents	Barrels
T-1155	169	External Floating	Heavy Naphtha	164,000

a. The permittee shall comply with the applicable sections of NESHAP, 40 CFR Part 63, Subpart CC for the affected tank.
   i. §63.642 General Standards
   ii. §63.646 Storage Vessel Provisions
   iii. §63.654 Reporting and Recordkeeping Requirements
b. The tank shall not store a VOC with a maximum vapor pressure greater than 0.05 psia under actual storage conditions.
c. The throughput for EU T-1155 shall not exceed 12,045,000 BPY based on a 12-month rolling total. [OAC 252:100-8-6(a)(1)]
d. The permittee shall record the throughput of the tank (monthly) and determine and record the true vapor pressure of the material stored in the tank (quarterly).
[OAC 252:100-8-6(a)(3)]
e. The limits of Permit No. 98-172-C (M-15) (PSD) for this EU are superceded by this permit.

EUG 170 SRU Incinerator. Emission limits for the SRU Incinerator. NO_X, CO, VOC, and PM_{10} emissions from the incinerator are based on combustion of 27.7 MMBTUH of auxiliary fuel, combustion of 552,396 SCFH of waste gas with a heat content of 23 BTU/SCF, and AP-42, Section 1.4 (7/98). SO_2 emissions are based on a flow rate of 630,000 DSCFH @ 0% O_2 and the NSPS, Subpart J, SO_2 emission limit of 250 ppmdv.

EU	Point	Description	MMBTUH
SBH-001	P-170	SRU Incinerator	40.4

NO_X		SO_2	
Lb/hr	**TPY**	**lb/hr**	**TPY**
4.0	17.4	26.2[1]	114.7

[1] – 2-hour average of contiguous 1-hour averages.

a. The permittee shall incorporate the following BACT for reduction of SO_2 emissions. [OAC 252:100-8-6(a)]
   i. The SRU shall be equipped with a tail gas treating unit (TGTU). The TGTU shall process the off-gases from the SRU.

b. EU SBH-001 is subject to New Source Performance Standards (NSPS), Subpart J and shall comply with all applicable provisions. [40 CFR Part 60, Subpart J]
   i. § 60.104 Standards for sulfur dioxide (SO_2) – (a)(2)(i);
   ii. § 60.105 Monitoring of operations – (a)(5)(i & ii) & (e)(4)(i);
   iii. § 60.106 Test methods and procedures – (a) & (f)(1 & 3).

c. EU SBH-001 is subject to NESHAP, Subpart UUU and shall comply with all applicable provisions. [40 CFR Part 63, Subpart UUU]
   i. § 63.1568 What are my requirements for HAP emissions from sulfur recovery units? – (a)(1)(i), (b)(1, 2, 5, 6, & 7), & (c)(1 & 2);
   ii. § 60.105 63.1569 What are my requirements for HAP emissions from bypass lines? – (a)(1 & 3), (b)(1-4), & (c)(1 & 2);
   iii. § 63.1570 What are my general requirements for complying with this subpart? – (a) & (c-g);
   iv. 63.1571 How and when do I conduct a performance test or other initial compliance demonstration? – (a) & (b)(1-5);
   v. 63.1572 What are my monitoring installation, operation, and maintenance requirements? – (a)(1-4) & (d)(1-2);
   vi. 63.1574 What notifications must I submit and when? – (a)(1-3), (c), (d), & (f)(1, 2(i), 2(ii), 2(viii), 2(ix), & 2(x));
   vii. 63.1575 What reports must I submit and when? – (a-h);
   viii. 63.1576 What records must I keep, in what form, and for how long? – (a), (b)(1, 3, 4, 5), & (d-i);
   ix. 63.1577 What parts of the General Provisions apply to me?

d. EU SBH-001 is subject to OAC 252:100-31-26 and shall comply with all applicable provisions. [OAC 252:100-31-26]
   i. Hydrogen sulfide (H_2S) from any new petroleum or natural gas process equipment shall be removed from the exhaust gas stream or it shall be oxidized to SO_2. H_2S emissions shall be reduced by 95% of the H_2S in the exhaust gas. [OAC 252:100-31-26(a)(1)]
   ii. Sulfur recovery plants operating in conjunction with any refinery process shall have the sulfur reduction efficiencies required below. [OAC 252:100-31-26(a)(2)(B)]
      A. When the sulfur content of the acid gas stream from the refinery process is greater than 5.0 LT/D but less than or equal to 150.0 LT/D, the required SO_2 emission reduction efficiency of the sulfur recovery plant shall be calculated using the following formula where Z is the minimum emission reduction efficiency required at all times and X is the sulfur feed rate expressed in LT/D of sulfur rounded to one decimal place: $Z = 92.34\ (X^{0.00774})$ [OAC 252:100-31-26(a)(2)(D)]
   iii. All new thermal devices for petroleum and natural gas processing facilities regulated under OAC 252:100-31-26(a)(1) shall have installed, calibrated, maintained, and operated an alarm system that will signal noncombustion of the gas. [OAC 252:100-31-26(c)]

EUG 171 Hot Oil Heater (SBH-002). Emission limits and standards for EU SBH-002 are listed below. Emissions from SBH-002 are based on a maximum rated capacity (HHV) of 20 MMBTUH, the respective emissions factors from AP-42, Section 1.4 (7/98), and a fuel gas H_2S concentration of 159 ppmdv.

EU	**Point**	**Description**	**MMBTUH**
SBH-002	P-171	Hot Oil Heater	20.0

NO_X		**CO**	
lb/hr	**TPY**	**lb/hr**	**TPY**
1.0	4.3	1.7	7.2

a. EU SBH-002 is subject to New Source Performance Standards (NSPS), Subpart Dc and shall comply with all applicable provisions. [40 CFR Part 60, Subpart Dc]
   i. The permittee shall record and maintain records of the amounts of each fuel combusted in EU SBH-002 during each day. [40 CFR 60.48c(g)]
b. EU SBH-002 is subject to New Source Performance Standards (NSPS), Subpart J and shall comply with all applicable provisions. [40 CFR Part 60, Subpart J]
   i. § 60.104 Standards for SO_2 – (a)(1);
   ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii);
   iii. § 60.106 Test methods and procedures – (e).
c. EU SBH-002 shall only be fired with refinery fuel gas. [OAC 252:100-8-6(a)(1)]
d. EU SBH-002 shall be equipped and operated with LNB and emissions of NO_X shall not exceed 0.06 lb/MMBTU.

e. Compliance with the emission limitations shall be based on the fuel consumption, fuel heat content, and the emission factors used to calculate emissions indicated above. Compliance with the TPY limits shall be based on a 12-month rolling total.

f. EU SBH-002 is subject to NESHAP, Subpart DDDDD and shall comply with all applicable provisions. [40 CFR Part 63, Subpart DDDDD]
   i. § 63.7495 When do I have to comply with this subpart? - (a) & (d)
   ii. § 63.7500 What emission limits, work practice standards, and operating limits must I meet? - (a)(1)
   iii. § 63.7505 What are my general requirements for complying with this subpart? - (a), (b), (d) & (e)
   iv. § 63.7510 What are my initial compliance requirements and by what date must I conduct them? - (a), (c), (e) & (g)
   v. § 63.7515 When must I conduct subsequent performance tests or fuel analyses? - (a), (e) & (g)
   vi. § 63.7520 What performance tests and procedures must I use? - (a), (b), (d), & (e-g)
   vii. § 63.7530 How do I demonstrate initial compliance with the emission limits and work practice standards? - (a)& (e)
   viii. § 63.7535 How do I monitor and collect data to demonstrate continuous compliance? (a) & (c)
   ix. § 63.7540 How do I demonstrate continuous compliance with the emission limits and work practice standards? - (a), (b), (c) & (d)
   x. § 63.7545 What notifications must I submit and when? - (a), (c), (d) & (e)
   xi. § 63.7550 What reports must I submit and when? - (a), (b), (c), (d), (e) & (g)
   xii. § 63.7555 What records must I keep? - (a) & (d)
   xiii. § 63.7560 In what form and how long must I keep my records? - (a), (b) & (c)
   xiv. § 63.7565 What parts of the General Provisions apply to me?

EUG 172 Regenerated Amine Storage Tank (TK-AB001). Emissions from EU TK-AB001 are based on TANKS4.0, a throughput of 12,463,046 BPY, and a H_2S concentration of 0.1% by weight and are considered insignificant (<5 TPY).

EU	Point	Roof Type	Contents	Barrels
TK-AB001	P-172	Cone	Amine	895

a. The throughput for EU TK-AB001 shall not exceed 12,463,046 BPY based on a 12-month rolling total. [OAC 252:100-8-6(a)(1)]

b. The permittee shall record the throughput of the tank (monthly). [OAC 252:100-8-6(a)(3)]

EUG 173 Liquid Sulfur Storage Tank (TK-SB001). Emissions from EU TK-SB001 are based on a H_2S concentration of 8,000 ppmv, a run-down rate of 12,100 lb/hr of molten sulfur (130 LTD), and the density of molten sulfur (124.8 lb/CF). These emissions are vented to the SRU incinerator and are incorporated into that limit as SO_2.

EU	Point	Roof Type	Contents	Barrels
TK-SB001	P-173	Cone	Sulfur	3,300

a. EU TK-SB001 shall be vented to the SRU incinerator at all times. [OAC 252:100-8-6(a)(1)]
b. The throughput for EU TK-SB001 shall not exceed 130 LTD based on a 12-month rolling average. [OAC 252:100-8-6(a)(1)]
c. The permittee shall record the throughput of the tank (monthly). [OAC 252:100-8-6(a)(3)]

EUG 174 Molten Sulfur Railcar Loading Rack (LR-SB001). Emissions from EU LR-SB001 are based on a H_2S concentration of 8,000 ppmv, a loading rate of 100,000 lb/hr of molten sulfur, and the density of molten sulfur (124.8 lb/CF). These emissions are vented to the SRU incinerator and are incorporated into that limit as SO_2.

EU	Point	Loading Rack	Loading Arm
LR-SB001	P-171	1	1
			2
			3

a. EU LR-SB001 shall be vented to the SRU incinerator at all times. [OAC 252:100-8-6(a)(1)]
b. EU LR-SB001 is subject to OAC 252:100-31-26 and shall comply with all applicable provisions. [OAC 252:100-31-26]
   i. H_2S from any new petroleum or natural gas process equipment shall be removed from the exhaust gas stream or it shall be oxidized to SO_2. H_2S emissions shall be reduced by 95% of the H_2S in the exhaust gas. [OAC 252:100-31-26(a)(1)]
   ii. All new thermal devices for petroleum and natural gas processing facilities regulated under OAC 252:100-31-26(a)(1) shall have installed, calibrated, maintained, and operated an alarm system that will signal noncombustion of the gas. [OAC 252:100-31-26(c)]

EUG 175 Wastewater Treatment Plant (WWTP) Incinerator. Emission limits for the WWTP Incinerator. Emissions from HI-8801 are based on a maximum rated auxiliary fuel flow of 15 MMBTUH (HHV), a flow rate of 198,000 SCFH (42 lb/hr) with a heat content of 21,344 BTU/lb, a nitrogen content of 315 ppmdv, an H_2S concentration of 159 ppmdv and a combustion efficiency of 95%, and the emissions factors from AP-42, Section 1.4 (7/98), except for emissions of NO_X, which are based on an emission factor of 0.12 lb/MMBTU.

EU	Point	Description	MMBTUH
HI-8801	P-176	WWTP Incinerator	15.0

NO_X		CO		SO_2		VOC	
lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
8.9	39.0	1.3	5.7	5.5	24.1	2.5	11.1

a. EU HI-8801 is subject to NSPS, Subpart J and shall comply with all applicable provisions. [40 CFR Part 60, Subpart J]
   i. § 60.104 Standards for sulfur dioxide – (a)(1)
   ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii)
   iii. § 60.106 Test methods and procedures – (e)

b. All off-gases from the WWTP Bioreactors shall be combusted by a properly operated and maintained thermal oxidizer.

c. The temperature of the combustion zone in the Thermal Oxidizer of EU HI-8801 shall not drop below 1,100 ºF.

d. The permittee shall continuously monitor and record the temperature of the combustion zone of the Thermal Oxidizer of EU HI-8801 (daily average).

e. EU HI-8801 shall not process more than 198,000 SCF/hr of waste gas based on a weekly or monthly average as specified in accordance with paragraph (h) as determined by site-specific parametric association of waste-gas generation as a function of air flow rate into the bioreactors.

f. The ammonia concentration of the waste gases vented to the WWTP Incinerator shall not exceed 315 ppmv based on a weekly or monthly average as specified in accordance with paragraph (h).

g. The facility shall determine and record weekly the ammonia concentration and flow of the waste gases vented to the WWTP Incinerator. If four consecutive weekly tests are in compliance with the ammonia and flow limitations, the testing and calculation frequency may be reduced to monthly testing and calculations. Upon any showing of non-compliance with the ammonia concentration or flow limitations, the testing and calculation frequency shall revert to weekly.

h. Compliance with the emission limitations shall be based on the fuel and waste gas combustion, fuel and waste gas heat content, waste gas ammonia concentrations, and the emission factors used to calculate emissions indicated above. Compliance with the TPY limits shall be based on a 12-month rolling total.

EUG 180 Co-Processor Heater (H-6503). Emissions from H-6503 are based on a maximum rated capacity (HHV) of 5.0 MMBTUH, the respective emissions factors from AP-42, Section 1.4 (7/98), and a fuel gas H_2S concentration of 159 ppmdv, except for emissions of NO_X which are based on an emission factor of 0.06 lb/MMBTU. Emissions from EU H-6503 are considered insignificant (<5 TPY).

EU	Point	Description	MMBTUH
H-6503	P-180	Co-Processor Heater	5.0

a. EU H-6503 is subject to New Source Performance Standards (NSPS), Subpart J and shall comply with all applicable provisions. [40 CFR Part 60, Subpart J]
   i. § 60.104 Standards for SO_2 – (a)(1);
   ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii);
   iii. § 60.106 Test methods and procedures – (e).

b. EU H-6503 shall only be fired with refinery fuel gas. [OAC 252:100-8-6(a)(1)]

c. EU H-6503 shall be equipped and operated with LNB and emissions of NO_X shall not exceed 0.06 lb/MMBTU. [OAC 252:100-8-6(a)(1)]

EUG 181 Sat-Gas Debutanizer Reboiler (H-302). Emissions from H-302 are based on a maximum rated capacity (HHV) of 11.0 MMBTUH, the respective emissions factors from AP-42, Section 1.4 (7/98), and a fuel gas H_2S concentration of 159 ppmdv, except for emissions of NO_X which are based on an emission factor of 0.06 lb/MMBTU. Emissions from EU H-6503 are considered insignificant (<5 TPY).

EU	Point	Description	MMBTUH
H-302	P-181	Sat-Gas Debutanizer Reboiler	11.0

a. EU H-302 is subject to New Source Performance Standards (NSPS), Subpart J and shall comply with all applicable provisions. [40 CFR Part 60, Subpart J]
   i. § 60.104 Standards for SO_2 – (a)(1);
   ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii);
   iii. § 60.106 Test methods and procedures – (e).

b. EU H-302 shall only be fired with refinery fuel gas. [OAC 252:100-8-6(a)(1)]

c. EU H-302 shall be equipped and operated with LNB and emissions of NO_X shall not exceed 0.06 lb/MMBTU. [OAC 252:100-8-6(a)(1)]

d. EU H-302 is subject to NESHAP, Subpart DDDDD and shall comply with all applicable provisions. [40 CFR Part 63, Subpart DDDDD]
   i. § 63.7495 When do I have to comply with this subpart? - (a) & (d)
   ii. § 63.7500 What emission limits, work practice standards, and operating limits must I meet? - (a)(1)
   iii. § 63.7505 What are my general requirements for complying with this subpart? - (a), (b), (d) & (e)
   iv. § 63.7510 What are my initial compliance requirements and by what date must I conduct them? - (a), (c), (e) & (g)
   v. § 63.7515 When must I conduct subsequent performance tests or fuel analyses? - (a), (e) & (g)
   vi. § 63.7520 What performance tests and procedures must I use? - (a), (b), (d), & (e-g)
   vii. § 63.7530 How do I demonstrate initial compliance with the emission limits and work practice standards? - (a)& (e)
   viii. § 63.7535 How do I monitor and collect data to demonstrate continuous compliance? (a) & (c)
   ix. § 63.7540 How do I demonstrate continuous compliance with the emission limits and work practice standards? - (a), (b), (c) & (d)
   x. § 63.7545 What notifications must I submit and when? - (a), (c), (d) & (e)
   xi. § 63.7550 What reports must I submit and when? - (a), (b), (c), (d), (e) & (g)
   xii. § 63.7555 What records must I keep? - (a) & (d)
   xiii. § 63.7560 In what form and how long must I keep my records? - (a), (b) & (c)
   xiv. § 63.7565 What parts of the General Provisions apply to me?

EUG 182 NHT stripper Reboiler (H-402C). Emission limits and standards for EU H-402C are listed below. Emissions from H-402C are based on a maximum rated capacity (HHV) of 20.0 MMBTUH, the respective emissions factors from AP-42, Section 1.4 (7/98), and a fuel gas H_2S concentration of 159 ppmdv, except for emissions of NO_X which are based on an emission factor of 0.06 lb/MMBTU.

EU	**Point**	**Description**	**MMBTUH**
H-402C	P-182	NHT Stripper Reboiler	20.0

NO_X		**CO**	
lb/hr	**TPY**	**lb/hr**	**TPY**
1.2	5.3	1.7	7.2

a. EU H-402C is subject to New Source Performance Standards (NSPS), Subpart J and shall comply with all applicable provisions. [40 CFR Part 60, Subpart J]
   i. § 60.104 Standards for SO_2 – (a)(1);
   ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii);
   iii. § 60.106 Test methods and procedures – (e).
b. EU H-402C shall only be fired with refinery fuel gas. [OAC 252:100-8-6(a)(1)]
c. EU H-402C shall be equipped and operated with LNB and emissions of NO_X shall not exceed 0.06 lb/MMBTU. [OAC 252:100-8-6(a)(1)]
d. Compliance with the emission limitations shall be based on the fuel consumption, fuel heat content, and the emission factors used to calculate emissions indicated above. Compliance with the TPY limits shall be based on a 12-month rolling total.
e. EU H-402C is subject to NESHAP, Subpart DDDDD and shall comply with all applicable provisions. [40 CFR Part 63, Subpart DDDDD]
   i. § 63.7495 When do I have to comply with this subpart? - (a) & (d)
   ii. § 63.7500 What emission limits, work practice standards, and operating limits must I meet? - (a)(1)
   iii. § 63.7505 What are my general requirements for complying with this subpart? - (a), (b), (d) & (e)
   iv. § 63.7510 What are my initial compliance requirements and by what date must I conduct them? - (a), (c), (e) & (g)
   v. § 63.7515 When must I conduct subsequent performance tests or fuel analyses? - (a), (e) & (g)
   vi. § 63.7520 What performance tests and procedures must I use? - (a), (b), (d), & (e-g)
   vii. § 63.7530 How do I demonstrate initial compliance with the emission limits and work practice standards? - (a)& (e)
   viii. § 63.7535 How do I monitor and collect data to demonstrate continuous compliance? (a) & (c)
   ix. § 63.7540 How do I demonstrate continuous compliance with the emission limits and work practice standards? - (a), (b), (c) & (d)
   x. § 63.7545 What notifications must I submit and when? - (a), (c), (d) & (e)
   xi. § 63.7550 What reports must I submit and when? - (a), (b), (c), (d), (e) & (g)

xii. § 63.7555 What records must I keep? - (a) & (d)
xiii. § 63.7560 In what form and how long must I keep my records? - (a), (b) & (c)
xiv. § 63.7565 What parts of the General Provisions apply to me?

EUG 183 NHT Reactor Inter-Heater (H-408). Emissions from H-408 are based on a maximum rated capacity (HHV) of 12.0 MMBTUH, the respective emissions factors from AP-42, Section 1.4 (7/98), and a fuel gas H_2S concentration of 159 ppmdv, except for emissions of NO_X which are based on an emission factor of 0.06 lb/MMBTU. Emissions from EU H-408 are considered insignificant (<5 TPY).

EU	Point	Description	MMBTUH
H-408	P-183	NHT Reactor Inter-Heater	12.0

a. EU H-408 is subject to New Source Performance Standards (NSPS), Subpart J and shall comply with all applicable provisions. [40 CFR Part 60, Subpart J]
   i. § 60.104 Standards for SO_2 – (a)(1);
   ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii);
   iii. § 60.106 Test methods and procedures – (e).
b. EU H-408 shall only be fired with refinery fuel gas. [OAC 252:100-8-6(a)(1)]
c. EU H-408 shall be equipped and operated with LNB and emissions of NO_X shall not exceed 0.06 lb/MMBTU. [OAC 252:100-8-6(a)(1)]
d. EU H-408 is subject to NESHAP, Subpart DDDDD and shall comply with all applicable provisions. [40 CFR Part 63, Subpart DDDDD]
   i. § 63.7495 When do I have to comply with this subpart? - (a) & (d)
   ii. § 63.7500 What emission limits, work practice standards, and operating limits must I meet? - (a)(1)
   iii. § 63.7505 What are my general requirements for complying with this subpart? - (a), (b), (d) & (e)
   iv. § 63.7510 What are my initial compliance requirements and by what date must I conduct them? - (a), (c), (e) & (g)
   v. § 63.7515 When must I conduct subsequent performance tests or fuel analyses? - (a), (e) & (g)
   vi. § 63.7520 What performance tests and procedures must I use? - (a), (b), (d), & (e-g)
   vii. § 63.7530 How do I demonstrate initial compliance with the emission limits and work practice standards? - (a)& (e)
   viii. § 63.7535 How do I monitor and collect data to demonstrate continuous compliance? (a) & (c)
   ix. § 63.7540 How do I demonstrate continuous compliance with the emission limits and work practice standards? - (a), (b), (c) & (d)
   x. § 63.7545 What notifications must I submit and when? - (a), (c), (d) & (e)
   xi. § 63.7550 What reports must I submit and when? - (a), (b), (c), (d), (e) & (g)
   xii. § 63.7555 What records must I keep? - (a) & (d)
   xiii. § 63.7560 In what form and how long must I keep my records? - (a), (b) & (c)
   xiv. § 63.7565 What parts of the General Provisions apply to me?

EUG 184 Emergency Water-Curtain Pumps (EWCP-1, EWCP-2, and EWCP-3). Emissions from the EWCP are based on 100 hours of operation a year, a maximum fuel input of 34.2 gal/hr, a diesel fuel heating value of 19,300 BTU/lb, a fuel sulfur content of 0.05% by weight, and AP-42, Section 3.4 (10/96). Emissions from EU EWCP-1, EWCP-2, and EWCP-3 are considered insignificant (<5 TPY).

EU	Point	Make/Model	HP	Const. Date
EWCP-1	P-185	Caterpillar 3412	660	2004
EWCP-2	P-186	Caterpillar 3412	660	2004
EWCP-3	P-187	Caterpillar 3412	660	2004

a. EU EWCP-1, EWCP-2, and EWCP-3 shall not operate more than 100 hours per year each based on a 12-month rolling total. [OAC 252:100-8-6(a)(1)]
b. EU EWCP-1, EWCP-2, and EWCP-3 shall be fitted with non-resettable hour-meters.
c. EU EWCP-1, EWCP-2, and EWCP-3 shall only be fired with diesel fuel with a sulfur content of less than 0.05% by weight (on-road low-sulfur diesel performance specification). [OAC 252:100-31]
d. The permittee shall maintain records of the diesel fuel purchase receipts documenting the sulfur content for each delivery of diesel fuel or shall determine and record the fuel sulfur content for each delivery of diesel fuel for the generators. [OAC 252:100-43]
e. A serial number or another acceptable form of permanent (non-removable) identification shall be on each engine.
f. Each engine shall only be operated with a governor that limits the engine's RPM to no greater than 1,750 RPM. The governor shall be checked every quarter to ensure that the engine does not exceed 1,750 RPM.

EUG 200 Crude Unit Fugitive VOC Sources (Area 100). Fugitive VOC emissions are estimated based on existing equipment items but do not have a specific limitation except to comply with the applicable LDAR program.

EU	Point	Number Items	Type of Equipment
Area 100	F-100	2,478	Valves
		4,249	Flanges
		72	Other
		3	Compressors
		29	Pump Seals

a. All affected equipment, in HAP service (contacting >5% by weight HAP), shall comply with NESHAP, 40 CFR Part 63, Subpart CC. The permittee shall comply with the applicable sections for each affected component. [40 CFR Part 63, Subpart CC]
   i. §63.642 General Standards – (c), (d)(1), (e), & (f);
   ii. §63.648 Equipment Leak Standards – (a), (b), (c), & (e-i);
   iii. §63.654 Reporting and Recordkeeping Requirements – (d), & (f-h).

b. Equipment determined not to be in HAP service (contacting <5% by weight HAP) and which is in VOC service (contacting >10% by weight HAP) shall comply with the requirements of NSPS 40 CFR Part 60, Subpart GGG. [40 CFR Part 60, Subpart GGG]
   i. §60.592 Standards (a-e);
   ii. §60.593 Exceptions (a-e).

EUG 204 Unsaturated Gas Plant Fugitive VOC Sources (Area 250). Fugitive VOC emissions are estimated based on existing equipment items but do not have a specific limitation except to comply with the applicable LDAR program.

EU	Point	Number Items	Type of Equipment
Area 200	F-104	617	Valves
		969	Flanges
		8	Other

a. All affected equipment, in HAP service (contacting >5% by weight HAP), shall comply with NESHAP, 40 CFR Part 63, Subpart CC. The permittee shall comply with the applicable sections for each affected component. [40 CFR Part 63, Subpart CC]
   i. §63.642 General Standards – (c), (d)(1), (e), & (f);
   ii. §63.648 Equipment Leak Standards – (a), (b), (c), & (e-i);
   iii. §63.654 Reporting and Recordkeeping Requirements – (d), & (f-h).

b. Equipment determined not to be in HAP service (contacting <5% by weight HAP) and which is in VOC service (contacting >10% by weight HAP) shall comply with the requirements of NSPS 40 CFR Part 60, Subpart GGG. [40 CFR Part 60, Subpart GGG]
   i. §60.592 Standards (a-e);
   ii. §60.593 Exceptions (a-e).

EUG 206 Sat. Gas Plant Fugitive VOC Sources (Area 300). Fugitive VOC emissions are estimated based on existing equipment items but do not have a specific limitation except to comply with the applicable LDAR program.

EU	Point	Number Items	Type of Equipment
Area 300	F-106	857	Valves
		1,457	Flanges
		30	Other
		7	Pump Seals

a. All affected equipment, in HAP service (contacting >5% by weight HAP), shall comply with NESHAP, 40 CFR Part 63, Subpart CC. The permittee shall comply with the applicable sections for each affected component. [40 CFR Part 63, Subpart CC]
   i. §63.642 General Standards – (c), (d)(1), (e), & (f);
   ii. §63.648 Equipment Leak Standards – (a), (b), (c), & (e-i);
   iii. §63.654 Reporting and Recordkeeping Requirements – (d), & (f-h).

b. Equipment determined not to be in HAP service (contacting <5% by weight HAP) and which is in VOC service (contacting >10% by weight HAP) shall comply with the requirements of NSPS 40 CFR Part 60, Subpart GGG. [40 CFR Part 60, Subpart GGG]
   i. §60.592 Standards (a-e);
   ii. §60.593 Exceptions (a-e).

EUG 207 Reformer "Platformer" Fugitive VOC Sources (Area 400). Fugitive VOC emissions are estimated based on existing equipment items but do not have a specific limitation except to comply with the applicable LDAR program.

EU	**Point**	**Number Items**	**Type of Equipment**
Area 400	F-107	866	Valves
		1,472	Flanges
		20	Other
		3	Compressors
		5	Pump Seals

a. All affected equipment, in HAP service (contacting >5% by weight HAP), shall comply with NESHAP, 40 CFR Part 63, Subpart CC. The permittee shall comply with the applicable sections for each affected component. [40 CFR Part 63, Subpart CC]
   i. §63.642 General Standards – (c), (d)(1), (e), & (f);
   ii. §63.648 Equipment Leak Standards – (a), (b), (c), & (e-i);
   iii. §63.654 Reporting and Recordkeeping Requirements – (d), & (f-h).

b. Equipment determined not to be in HAP service (contacting <5% by weight HAP) and which is in VOC service (contacting >10% by weight HAP) shall comply with the requirements of NSPS 40 CFR Part 60, Subpart GGG. [40 CFR Part 60, Subpart GGG]
   i. §60.592 Standards (a-e);
   ii. §60.593 Exceptions (a-e).

EUG 210 Cat Feed Hydrotreater Unit Fugitive VOC (Area 650). Fugitive VOC emissions are estimated based on existing equipment items but do not have a specific limitation except to comply with the applicable LDAR program.

EU	**Point**	**Number Items**	**Type of Equipment**
Area 650	F-110	1,544	Valves
		2,597	Flanges
		57	Other
		3	Compressor
		4	Pump Seals

a. All affected equipment, in HAP service (contacting >5% by weight HAP), shall comply with NESHAP, 40 CFR Part 63, Subpart CC. The permittee shall comply with the applicable sections for each affected component. [40 CFR Part 63, Subpart CC]
   i. §63.642 General Standards – (c), (d)(1), (e), & (f);
   ii. §63.648 Equipment Leak Standards – (a), (b), (c), & (e-i);
   iii. §63.654 Reporting and Recordkeeping Requirements – (d), & (f-h).

b. Equipment determined not to be in HAP service (contacting <5% by weight HAP) and which is in VOC service (contacting >10% by weight HAP) shall comply with the requirements of NSPS 40 CFR Part 60, Subpart GGG. [40 CFR Part 60, Subpart GGG]
   i. §60.592 Standards (a-e);
   ii. §60.593 Exceptions (a-e).

EUG 214 WWTP Fugitive Sources. Fugitive VOC emissions are estimated based on existing equipment items but do not have a specific limitation except to comply with the applicable LDAR program.

EU	**Point**	**Number Items**	**Type of Equipment**
ASU	F-114	233	Valves
		416	Flanges
		4	Pump Seals
		3	Drains

a. Equipment determined to be in VOC service (contacting >10% by weight VOC) shall comply with the requirements of NSPS, 40 CFR Part 60, Subpart GGG.
   i. §60.592 Standards
   ii. §60.593 Exceptions

EUG 215 LPG Loading Operations Fugitive VOC Emissions. Fugitive VOC emissions are estimated based on the number of loading operations conducted in a year. Emission limits and standards for the LPG Loading Operations are listed below.

EU	Point	Number Items	Type of Equipment
LPG	F-115	225	Valves
		383	Flanges
		6	Other
		2	Pump Seals
		2	Loading Arms

a. Equipment determined to be in VOC service (contacting >10% by weight VOC) shall comply with the requirements of NSPS, 40 CFR Part 60, Subpart GGG.
   i. §60.592 Standards
   ii. §60.593 Exceptions
b. The LPG Loading operations are limited to the following throughputs based on a 12-month rolling total:
   i. Tank Truck Loadout - 750,000 barrels LPG per year;
   ii. Railcar Loadout - 1,500,000 barrels per year;
   iii. LPG Unloading – 1,080,765 barrels per year.
c. The permittee shall record the amounts loaded and unloaded at the LPG tank truck and railcar loading racks (monthly). [OAC 252:100-8-6(a)(3)]
d. The loading hoses shall be high pressure hoses equipped with block valves and end caps.

e. All loading and vapor lines shall be equipped with fittings that make vapor tight connections and which must be closed when disconnected or which close automatically when disconnected. [OAC 252:100-37-16 (a)(1)(A)(ii)]

f. The loading system shall be of sufficient capacity to receive all vapors and gases displaced from the tank trucks or trailers being loaded. [OAC 252:100-37-16 (a)(1)(B)(ii)]

g. A means shall be provided to prevent VOC drainage from the loading device when it is removed from any tank truck or trailer or to accomplish complete drainage before removal. [OAC 252:100-37-16 (a)(2)]

EUG 217 SWS No. 3 Fugitive VOC Equipment (Area 840). Fugitive VOC emissions are estimated based on existing equipment items but do not have a specific limitation except to comply with the applicable LDAR program.

EU	Point	Number Items	Type of Equipment
		127	Valves
		165	Flanges
		6	Pump Seals

a. All affected equipment, in HAP service (contacting >5% by weight HAP), shall comply with NESHAP, 40 CFR Part 63, Subpart CC. The permittee shall comply with the applicable sections for each affected component. [40 CFR Part 63, Subpart CC]
   i. §63.642 General Standards – (c), (d)(1), (e), & (f);
   ii. §63.648 Equipment Leak Standards – (a), (b), (c), & (e-i);
   iii. §63.654 Reporting and Recordkeeping Requirements – (d), & (f-h).

b. Equipment determined not to be in HAP service (contacting <5% by weight HAP) and which is in VOC service (contacting >10% by weight HAP) shall comply with the requirements of NSPS 40 CFR Part 60, Subpart GGG. [40 CFR Part 60, Subpart GGG]
   i. §60.592 Standards (a-e);
   ii. §60.593 Exceptions (a-e).

EUG 220 Naphtha Hydrotreater (NHT) Fugitive VOC (Area 650). Fugitive VOC emissions are estimated based on existing equipment items but do not have a specific limitation except to comply with the applicable LDAR program.

EU	Point	Number Items	Type of Equipment
Area 400	F-107	1,510	Valves
		2,544	Flanges
		63	Other
		4	Compressor
		18	Pump Seals

a. All affected equipment, in HAP service (contacting >5% by weight HAP), shall comply with NESHAP, 40 CFR Part 63, Subpart CC. The permittee shall comply with the applicable sections for each affected component. [40 CFR Part 63, Subpart CC]
   i. §63.642 General Standards – (c), (d)(1), (e), & (f);

ii. §63.648 Equipment Leak Standards – (a), (b), (c), & (e-i);
iii. §63.654 Reporting and Recordkeeping Requirements – (d), & (f-h).

b. Equipment determined not to be in HAP service (contacting <5% by weight HAP) and which is in VOC service (contacting >10% by weight HAP) shall comply with the requirements of NSPS 40 CFR Part 60, Subpart GGG. [40 CFR Part 60, Subpart GGG]
i. §60.592 Standards (a-e);
ii. §60.593 Exceptions (a-e).

EUG 223 and 224 Asphalt and Gas-Oil/Slurry/#6 Fuel Oil Railcar and Tank Truck Loading Operations Fugitive VOC Emissions. Fugitive VOC emissions are estimated based on AP-42 (1/95), Section 5.2 and the amount of asphalt and gas-oil/slurry/#6 fuel oil loaded in a year. Emission limits and standards for the railcar and tank truck loading operations are listed below.

Railcar Loading

EU	Point	Loading Bays	Loading Arm
AsRail	F-124	2	1
			2
			3
			4

Tank Truck Loading

EU	Point	Loading Bays	Loading Arm
AsTruk	F-125	4	1
			2
			3
			4
			5
			6

a. The asphalt and gas-oil/slurry/#6 fuel oil loading operations are limited to the following throughputs based on a 12-month rolling total:
i. Aspahlt - 4,745,000 barrels;
ii. Gas-Oil/Slurry/#6 Fuel Oil - 191,625 barrels;

EUG 230: Amine Regenerator Unit #2 Wastewater Processing. Fugitive VOC emissions are estimated based on existing equipment items but do not have a specific limitation except to comply with the applicable LDAR programs.

EU	Point	Number Items	Type of Equipment
WWAB-001	F-AB001	12	P-Trap
		2	Junction Boxes

a. Equipment in VOC service (contacting >10% by weight HAP) shall comply with the requirements of NSPS 40 CFR Part 60, Subpart GGG. [40 CFR Part 60, Subpart GGG]
i. §60.592 Standards (a-e);
ii. §60.593 Exceptions (a-e).

EUG 231: SCOT Unit #2 Wastewater Processing. Fugitive VOC emissions are estimated based on existing equipment items but do not have a specific limitation except to comply with the applicable LDAR programs.

EU	Point	Number Items	Type of Equipment
WWSB-001	F-SB001	9	P-Trap
		1	Junction Box

a. Equipment in VOC service (contacting >10% by weight HAP) shall comply with the requirements of NSPS 40 CFR Part 60, Subpart GGG. [40 CFR Part 60, Subpart GGG]
   i. §60.592 Standards (a-e);
   ii. §60.593 Exceptions (a-e).

EUG 530: SCOT Unit #2 Fugitive Sources. Fugitive VOC emissions are estimated based on existing equipment items but do not have a specific limitation except to comply with the applicable LDAR programs.

EU	Point	Number Items	Type of Equipment
Area 530	F-530	282	Valves
		499	Flanges
		4	Other
		6	Pumps

a. Equipment in VOC service (contacting >10% by weight HAP) shall comply with the requirements of NSPS 40 CFR Part 60, Subpart GGG. [40 CFR Part 60, Subpart GGG]
   i. §60.592 Standards (a-e);
   ii. §60.593 Exceptions (a-e).

EUG 560: Amine Regeneration Unit #2 Fugitive Sources. Fugitive VOC emissions are estimated based on existing equipment items but do not have a specific limitation except to comply with the applicable LDAR programs.

EU	Point	Number Items	Type of Equipment
Area 560	F-560	314	Valves
		630	Flanges
		8	Other
		6	Pumps

a. Equipment in VOC service (contacting >10% by weight HAP) shall comply with the requirements of NSPS 40 CFR Part 60, Subpart GGG. [40 CFR Part 60, Subpart GGG]
   i. §60.592 Standards (a-e);
   ii. §60.593 Exceptions (a-e).

EUG 570: SRU TGTU #2 Fugitive Sources. Fugitive VOC emissions are estimated based on existing equipment items but do not have a specific limitation except to comply with the applicable LDAR programs.

EU	Point	Number Items	Type of Equipment
Area 570	F-570	252	Valves
		560	Flanges
		3	Other
		7	Pumps

a. Equipment in VOC service (contacting >10% by weight HAP) shall comply with the requirements of NSPS 40 CFR Part 60, Subpart GGG. [40 CFR Part 60, Subpart GGG]
   i. §60.592 Standards (a-e);
   ii. §60.593 Exceptions (a-e).

3. Certain equipment within the refinery is subject to NSPS, 40 CFR Part 60, Subpart QQQ and all affected equipment shall comply with all applicable requirements.
[40 CFR 60, NSPS, Subpart QQQ]

a. § 60.692–1 Standards: General.
b. § 60.692–2 Standards: Individual drain systems.
c. § 60.692–3 Standards: Oil-water separators.
d. § 60.692–4 Standards: Aggregate facility.
e. § 60.692–5 Standards: Closed vent systems and control devices.
f. § 60.692–6 Standards: Delay of repair.
g. § 60.692–7 Standards: Delay of compliance.
h. § 60.693–1 Alternative standards for individual drain systems.
i. § 60.693–2 Alternative standards for oil-water separators.
j. § 60.695 Monitoring of operations.
k. § 60.696 Performance test methods and procedures and compliance provisions.
l. § 60.697 Recordkeeping requirements.
m. § 60.698 Reporting requirements.

4. The Refinery is subject to NESHAP, 40 CFR Part 61, Subpart FF and shall comply with all applicable requirements. [40 CFR 61, NESHAP, Subpart FF]

a. § 61.342 Standards: General.
b. § 61.343 Standards: Tanks.
c. § 61.344 Standards: Surface Impoundments.
d. § 61.345 Standards: Containers.
e. § 61.346 Standards: Individual drain systems.
f. § 61.347 Standards: Oil-water separators.
g. § 61.348 Standards: Treatment processes.
h. § 61.349 Standards: Closed-vent systems and control devices.
i. § 61.350 Standards: Delay of repair.
j. § 61.351 Alternative standards for tanks.
k. § 61.352 Alternative standards for oilwater separators.

l. § 61.353 Alternative means of emission limitation.
m. § 61.354 Monitoring of operations.
n. § 61.355 Test methods, procedures, and compliance provisions.
o. § 61.356 Recordkeeping requirements.
p. § 61.357 Reporting requirements.

5. Certain equipment within the refinery is subject to NESHAP, 40 CFR Part 63, Subpart CC and all affected equipment shall comply with all applicable requirements including but not limited to: [40 CFR 63, NESHAP, Subpart CC]

a. § 63. 63.642 General Standards
b. § 63.643 Miscellaneous Process Vent Provisions
c. § 63.644 Monitoring for Miscellaneous Process Vents
d. § 63.645 Test Methods and Procedures for Miscellaneous Process Vents
e. § 63.646 Storage Vessel Provisions
f. § 63.647 Wastewater Provisions
g. § 63.648 Equipment Leak Standards
h. § 63.652 Emission Averaging Provisions
i. § 63.653 Monitoring, Recordkeeping, and Implementation Plan for Emissions Averaging
j. § 63.654 Reporting and Recordkeeping Requirements
k. The permittee shall comply with the provisions of 40 CFR Part 63 Subpart A as specified in Appendix to Subpart CC, Table 6.

5. Until 12 consecutive months of data has been collected to determine the 12-month rolling totals and averages applicable to the facility, the facility shall fill the missing data for the previous months with an estimated average monthly figure based on the applicable rolling total or average divided by 12. If there exists enough data to determine the values for the previous months, it can be used to determine the applicable 12-month rolling totals or averages.
[OAC 252:100-8-6(a)(3)]

6. The permittee shall maintain records as specified in Specific Condition 1 and 2 including but not limited to those listed below. These records shall be maintained on-site for at least five years after the date of recording and shall be provided to regulatory personnel upon request.
[OAC 252:100-43]

a. Records showing compliance with 12-month rolling totals (monthly) and 12-month rolling averages (daily and monthly) established in Specific Conditions 1 and 2.
b. Records showing compliance with emission limits (monthly) established in Specific Conditions 1 and 2.
c. Heater fuel usage (monthly) and heat content (quarterly).
d. The catalyst recirculation rate and the feedstock sulfur content of the catalytic reforming unit (quarterly).
e. The CO emission testing for the catalytic reforming unit (quarterly or semi-annual).
f. The flow rate and ammonia concentration of the WWTP being sent to the WWTP incinerator (weekly or monthly).
g. The WWTP Incinerator combustion zone temperature (daily).

h. The hours of operation of the EWCP.
i. The EWCP diesel fuel sulfur content (each delivery).
j. The inspection records for the EWCP governors (quarterly).
k. Records required by NSPS, Subparts Dc, J, GGG, and QQQ and NESHAP, Subparts CC, FF, and UUU.

7. When monitoring shows an exceedance of any of the limits of Specific Condition No. 1 or 2, the owner or operator shall comply with the provisions of OAC 252:100-9 for excess emissions. [OAC 252:100-9]

8. No later than 30 days after each anniversary date of the issuance of the Part 70 operating permit for this facility, the permittee shall submit to Air Quality Division of DEQ, with a copy to the US EPA, Region 6, a certification of compliance with the terms and conditions of the Part 70 operating permit. The following specific information for the past year is required to be included: [OAC 252:100-8-6 (c)(5)(A) & (D)]

a. Summary of records showing compliance with the 12-month rolling totals and 12-month rolling averages established in Specific Conditions 1 and 2 (monthly).
b. Summary of records showing compliance with the emission limits established in Specific Conditions 1 and 2 (monthly).
c. Summary of the records showing compliance with the catalytic reforming unit catalyst recirculation rate, feedstock sulfur content, and CO emission limitations (quarterly or semi-annual).
d. Summary of the flow rate and ammonia concentrations of the waste gases being vented to the WWTP Incinerator and (weekly or monthly).
e. Summary of exceedances of the minimum temperature limitation of the WWTP Incinerator (daily).
f. Summary of the inspection records for the EWCP governors (quarterly).

9. This permit supercedes Permit No. 78-081-O (M-1), 80-060-O (M-1), 80-068-O (M-1), 93-023-O (M-1), and 98-172-C (M-14) (PSD), which are now null and void.

TITLE V (PART 70) PERMIT TO OPERATE / CONSTRUCT
STANDARD CONDITIONS
(October 15, 2003)

SECTION I. DUTY TO COMPLY

A. This is a permit to operate / construct this specific facility in accordance with Title V of the federal Clean Air Act (42 U.S.C. 7401, et seq.) and under the authority of the Oklahoma Clean Air Act and the rules promulgated there under. [Oklahoma Clean Air Act, 27A O.S. § 2-5-112]

B. The issuing Authority for the permit is the Air Quality Division (AQD) of the Oklahoma Department of Environmental Quality (DEQ). The permit does not relieve the holder of the obligation to comply with other applicable federal, state, or local statutes, regulations, rules, or ordinances. [Oklahoma Clean Air Act, 27A O.S. § 2-5-112]

C. The permittee shall comply with all conditions of this permit. Any permit noncompliance shall constitute a violation of the Oklahoma Clean Air Act and shall be grounds for enforcement action, for revocation of the approval to operate under the terms of this permit, or for denial of an application to renew this permit. All applicable requirements (excluding state-only requirements) are enforceable by the DEQ, by EPA, and by citizens under section 304 of the Clean Air Act. This permit is valid for operations only at the specific location listed.
[OAC 252:100-8-1.3 and 8-6 (a)(7)(A) and (b)(1)]

D. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit. [OAC 252:100-8-6 (a)(7)(B)]

SECTION II. REPORTING OF DEVIATIONS FROM PERMIT TERMS

A. Any exceedance resulting from emergency conditions and/or posing an imminent and substantial danger to public health, safety, or the environment shall be reported in accordance with Section XIV. [OAC 252:100-8-6 (a)(3)(C)(iii)]

B. Deviations that result in emissions exceeding those allowed in this permit shall be reported consistent with the requirements of OAC 252:100-9, Excess Emission Reporting Requirements.
[OAC 252:100-8-6 (a)(3)(C)(iv)]

C. Oral notifications (fax is also acceptable) shall be made to the AQD central office as soon as the owner or operator of the facility has knowledge of such emissions but no later than 4:30 p.m. the next working day the permittee becomes aware of the exceedance. Within ten (10) working days after the immediate notice is given, the owner operator shall submit a written report describing the extent of the excess emissions and response actions taken by the facility. Every written report submitted under this section shall be certified by a responsible official.
[OAC 252:100-8-6 (a)(3)(C)(iii)(I) and (iv)]

SECTION III. MONITORING, TESTING, RECORDKEEPING & REPORTING

A. The permittee shall keep records as specified in this permit. These records, including monitoring data and necessary support information, shall be retained on-site or at a nearby field office for a period of at least five years from the date of the monitoring sample, measurement, report, or application, and shall be made available for inspection by regulatory personnel upon request. Support information includes all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. Where appropriate, the permit may specify that records may be maintained in computerized form.

[OAC 252:100-8-6 (a)(3)(B)(ii), 8-6 (c)(1), and 8-6 (c)(2)(B)]

B. Records of required monitoring shall include:

(1) the date, place and time of sampling or measurement;
(2) the date or dates analyses were performed;
(3) the company or entity which performed the analyses;
(4) the analytical techniques or methods used;
(5) the results of such analyses; and
(6) the operating conditions as existing at the time of sampling or measurement.

[OAC 252:100-8-6 (a)(3)(B)(i)]

C. No later than 30 days after each six (6) month period, after the date of the issuance of the original Part 70 operating permit, the permittee shall submit to AQD a report of the results of any required monitoring. All instances of deviations from permit requirements since the previous report shall be clearly identified in the report. [OAC 252:100-8-6 (a)(3)(C)(i) and (ii)]

D. If any testing shows emissions in excess of limitations specified in this permit, the owner or operator shall comply with the provisions of Section II of these standard conditions.

[OAC 252:100-8-6 (a)(3)(C)(iii)]

E. In addition to any monitoring, recordkeeping or reporting requirement specified in this permit, monitoring and reporting may be required under the provisions of OAC 252:100-43, Testing, Monitoring, and Recordkeeping, or as required by any provision of the Federal Clean Air Act or Oklahoma Clean Air Act.

F. Submission of quarterly or semi-annual reports required by any applicable requirement that are duplicative of the reporting required in the previous paragraph will satisfy the reporting requirements of the previous paragraph if noted on the submitted report.

G. Every report submitted under this section shall be certified by a responsible official.

[OAC 252:100-8-6 (a)(3)(C)(iv)]

H. Any owner or operator subject to the provisions of NSPS shall maintain records of the occurrence and duration of any start-up, shutdown, or malfunction in the operation of an affected facility or any malfunction of the air pollution control equipment. [40 CFR 60.7 (b)]

I. Any owner or operator subject to the provisions of NSPS shall maintain a file of all measurements and other information required by the subpart recorded in a permanent file suitable for inspection. This file shall be retained for at least two years following the date of such measurements, maintenance, and records. [40 CFR 60.7 (d)]

J. The permittee of a facility that is operating subject to a schedule of compliance shall submit to the DEQ a progress report at least semi-annually. The progress reports shall contain dates for achieving the activities, milestones or compliance required in the schedule of compliance and the dates when such activities, milestones or compliance was achieved. The progress reports shall also contain an explanation of why any dates in the schedule of compliance were not or will not be met, and any preventative or corrective measures adopted. [OAC 252:100-8-6 (c)(4)]

K. All testing must be conducted by methods approved by the Division Director under the direction of qualified personnel. All tests shall be made and the results calculated in accordance with standard test procedures. The permittee may request the use of alternative test methods or analysis procedures. The AQD shall approve or disapprove the request within 60 days. When a portable analyzer is used to measure emissions it shall be setup, calibrated, and operated in accordance with the manufacturer's instructions and in accordance with a protocol meeting the requirements of the "AQD Portable Analyzer Guidance" document or an equivalent method approved by Air Quality. [OAC 252:100-8-6 (a)(3)(A)(iv) and OAC 252:100-43]

L. The permittee shall submit to the AQD a copy of all reports submitted to the EPA as required by 40 CFR Part 60, 61, and 63, for all equipment constructed or operated under this permit subject to such standards. [OAC 252:100-4-5 and OAC 252:100-41-15]

SECTION IV. COMPLIANCE CERTIFICATIONS

A. No later than 30 days after each anniversary date of the issuance of the original Part 70 operating permit, the permittee shall submit to the AQD, with a copy to the US EPA, Region 6, a certification of compliance with the terms and conditions of this permit and of any other applicable requirements which have become effective since the issuance of this permit. The compliance certification shall also include such other facts as the permitting authority may require to determine the compliance status of the source.

[OAC 252:100-8-6 (c)(5)(A), (C)(v), and (D)]

B. The certification shall describe the operating permit term or condition that is the basis of the certification; the current compliance status; whether compliance was continuous or intermittent; the methods used for determining compliance, currently and over the reporting period; and a statement that the facility will continue to comply with all applicable requirements.

[OAC 252:100-8-6 (c)(5)(C)(i)-(iv)]

C. Any document required to be submitted in accordance with this permit shall be certified as being true, accurate, and complete by a responsible official. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the certification are true, accurate, and complete.
[OAC 252:100-8-5 (f) and OAC 252:100-8-6 (c)(1)]

D. Any facility reporting noncompliance shall submit a schedule of compliance for emissions units or stationary sources that are not in compliance with all applicable requirements. This schedule shall include a schedule of remedial measures, including an enforceable sequence of actions with milestones, leading to compliance with any applicable requirements for which the emissions unit or stationary source is in noncompliance. This compliance schedule shall resemble and be at least as stringent as that contained in any judicial consent decree or administrative order to which the emissions unit or stationary source is subject. Any such schedule of compliance shall be supplemental to, and shall not sanction noncompliance with, the applicable requirements on which it is based. Except that a compliance plan shall not be required for any noncompliance condition which is corrected within 24 hours of discovery.
[OAC 252:100-8-5 (e)(8)(B) and OAC 252:100-8-6 (c)(3)]

SECTION V. REQUIREMENTS THAT BECOME APPLICABLE DURING THE PERMIT TERM

The permittee shall comply with any additional requirements that become effective during the permit term and that are applicable to the facility. Compliance with all new requirements shall be certified in the next annual certification. [OAC 252:100-8-6 (c)(6)]

SECTION VI. PERMIT SHIELD

A. Compliance with the terms and conditions of this permit (including terms and conditions established for alternate operating scenarios, emissions trading, and emissions averaging, but excluding terms and conditions for which the permit shield is expressly prohibited under OAC 252:100-8) shall be deemed compliance with the applicable requirements identified and included in this permit. [OAC 252:100-8-6 (d)(1)]

B. Those requirements that are applicable are listed in the Standard Conditions and the Specific Conditions of this permit. Those requirements that the applicant requested be determined as not applicable are listed in the Evaluation Memorandum and are summarized in the Specific Conditions of this permit. [OAC 252:100-8-6 (d)(2)]

SECTION VII. ANNUAL EMISSIONS INVENTORY & FEE PAYMENT

The permittee shall file with the AQD an annual emission inventory and shall pay annual fees based on emissions inventories. The methods used to calculate emissions for inventory purposes shall be based on the best available information accepted by AQD.
[OAC 252:100-5-2.1, -5-2.2, and OAC 252:100-8-6 (a)(8)]

SECTION VIII. TERM OF PERMIT

A. Unless specified otherwise, the term of an operating permit shall be five years from the date of issuance. [OAC 252:100-8-6 (a)(2)(A)]

B. A source's right to operate shall terminate upon the expiration of its permit unless a timely and complete renewal application has been submitted at least 180 days before the date of expiration. [OAC 252:100-8-7.1 (d)(1)]

C. A duly issued construction permit or authorization to construct or modify will terminate and become null and void (unless extended as provided in OAC 252:100-8-1.4(b)) if the construction is not commenced within 18 months after the date the permit or authorization was issued, or if work is suspended for more than 18 months after it is commenced. [OAC 252:100-8-1.4(a)]

D. The recipient of a construction permit shall apply for a permit to operate (or modified operating permit) within 180 days following the first day of operation. [OAC 252:100-8-4(b)(5)]

SECTION IX. SEVERABILITY

The provisions of this permit are severable and if any provision of this permit, or the application of any provision of this permit to any circumstance, is held invalid, the application of such provision to other circumstances, and the remainder of this permit, shall not be affected thereby. [OAC 252:100-8-6 (a)(6)]

SECTION X. PROPERTY RIGHTS

A. This permit does not convey any property rights of any sort, or any exclusive privilege. [OAC 252:100-8-6 (a)(7)(D)]

B. This permit shall not be considered in any manner affecting the title of the premises upon which the equipment is located and does not release the permittee from any liability for damage to persons or property caused by or resulting from the maintenance or operation of the equipment for which the permit is issued. [OAC 252:100-8-6 (c)(6)]

SECTION XI. DUTY TO PROVIDE INFORMATION

A. The permittee shall furnish to the DEQ, upon receipt of a written request and within sixty (60) days of the request unless the DEQ specifies another time period, any information that the DEQ may request to determine whether cause exists for modifying, reopening, revoking, reissuing, terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the DEQ copies of records required to be kept by the permit. [OAC 252:100-8-6 (a)(7)(E)]

B. The permittee may make a claim of confidentiality for any information or records submitted pursuant to 27A O.S. 2-5-105(18). Confidential information shall be clearly labeled as such and shall be separable from the main body of the document such as in an attachment.

[OAC 252:100-8-6 (a)(7)(E)]

C. Notification to the AQD of the sale or transfer of ownership of this facility is required and shall be made in writing within 10 days after such date.

[Oklahoma Clean Air Act, 27A O.S. § 2-5-112 (G)]

SECTION XII. REOPENING, MODIFICATION & REVOCATION

A. The permit may be modified, revoked, reopened and reissued, or terminated for cause. Except as provided for minor permit modifications, the filing of a request by the permittee for a permit modification, revocation, reissuance, termination, notification of planned changes, or anticipated noncompliance does not stay any permit condition.

[OAC 252:100-8-6 (a)(7)(C) and OAC 252:100-8-7.2 (b)]

B. The DEQ will reopen and revise or revoke this permit as necessary to remedy deficiencies in the following circumstances: [OAC 252:100-8-7.3 and OAC 252:100-8-7.4(a)(2)]

(1) Additional requirements under the Clean Air Act become applicable to a major source category three or more years prior to the expiration date of this permit. No such reopening is required if the effective date of the requirement is later than the expiration date of this permit.

(2) The DEQ or the EPA determines that this permit contains a material mistake or that the permit must be revised or revoked to assure compliance with the applicable requirements.

(3) The DEQ determines that inaccurate information was used in establishing the emission standards, limitations, or other conditions of this permit. The DEQ may revoke and not reissue this permit if it determines that the permittee has submitted false or misleading information to the DEQ.

C. If “grandfathered” status is claimed and granted for any equipment covered by this permit, it shall only apply under the following circumstances: [OAC 252:100-5-1.1]

(1) It only applies to that specific item by serial number or some other permanent identification.

(2) Grandfathered status is lost if the item is significantly modified or if it is relocated outside the boundaries of the facility.

D. To make changes other than (1) those described in Section XVIII (Operational Flexibility), (2) administrative permit amendments, and (3) those not defined as an Insignificant Activity (Section XVI) or Trivial Activity (Section XVII), the permittee shall notify AQD. Such changes may require a permit modification. [OAC 252:100-8-7.2 (b)]

E. Activities that will result in air emissions that exceed the trivial/insignificant levels and that are not specifically approved by this permit are prohibited. [OAC 252:100-8-6 (c)(6)]

SECTION XIII. INSPECTION & ENTRY

A. Upon presentation of credentials and other documents as may be required by law, the permittee shall allow authorized regulatory officials to perform the following (subject to the permittee's right to seek confidential treatment pursuant to 27A O.S. Supp. 1998, § 2-5-105(18) for confidential information submitted to or obtained by the DEQ under this section):

(1) enter upon the permittee's premises during reasonable/normal working hours where a source is located or emissions-related activity is conducted, or where records must be kept under the conditions of the permit;
(2) have access to and copy, at reasonable times, any records that must be kept under the conditions of the permit;
(3) inspect, at reasonable times and using reasonable safety practices, any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit; and
(4) as authorized by the Oklahoma Clean Air Act, sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the permit.

[OAC 252:100-8-6 (c)(2)]

SECTION XIV. EMERGENCIES

A. Any emergency and/or exceedance that poses an imminent and substantial danger to public health, safety, or the environment shall be reported to AQD as soon as is practicable; but under no circumstance shall notification be more than 24 hours after the exceedance. [The degree of promptness in reporting shall be proportional to the degree of danger.]

[OAC 252:100-8-6 (a)(3)(C)(iii)(II)]

B. An "emergency" means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under this permit, due to unavoidable increases in emissions attributable to the emergency. [OAC 252:100-8-2]

C. An emergency shall constitute an affirmative defense to an action brought for noncompliance with such technology-based emission limitation if the conditions of paragraph D below are met.

[OAC 252:100-8-6 (e)(1)]

D. The affirmative defense of emergency shall be demonstrated through properly signed, contemporaneous operating logs or other relevant evidence that:

(1) an emergency occurred and the permittee can identify the cause or causes of the emergency;
(2) the permitted facility was at the time being properly operated;
(3) during the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards or other requirements in this permit;
(4) the permittee submitted notice of the emergency to AQD within 24 hours of the time when emission limitations were exceeded due to the emergency. This notice shall contain a description of the emergency, the probable cause of the exceedance, any steps taken to mitigate emissions, and corrective actions taken; and
(5) the permittee submitted a follow up written report within 10 working days of first becoming aware of the exceedance.

[OAC 252:100-8-6 (e)(2), (a)(3)(C)(iii)(I) and (IV)]

E. In any enforcement proceeding, the permittee seeking to establish the occurrence of an emergency shall have the burden of proof. [OAC 252:100-8-6 (e)(3)]

SECTION XV. RISK MANAGEMENT PLAN

The permittee, if subject to the provision of Section 112(r) of the Clean Air Act, shall develop and register with the appropriate agency a risk management plan by June 20, 1999, or the applicable effective date. [OAC 252:100-8-6 (a)(4)]

SECTION XVI. INSIGNIFICANT ACTIVITIES

Except as otherwise prohibited or limited by this permit, the permittee is hereby authorized to operate individual emissions units that are either on the list in Appendix I, or whose actual calendar year emissions do not exceed any of the limits below. Any activity to which a State or federal applicable requirement applies is not insignificant even if it meets the criteria below or is included on the insignificant activities list. [OAC 252:100-8-2]

(1) 5 tons per year of any one criteria pollutant.
(2) 2 tons per year for any one hazardous air pollutant (HAP) or 5 tons per year for an aggregate of two or more HAP's, or 20 percent of any threshold less than 10 tons per year for single HAP that the EPA may establish by rule.
(3) 0.6 tons per year for any one category A substance, 1.2 tons per year for any one category B substance or 6 tons per year for any one category C substance as defined in 252:100-41-40.

SECTION XVII. TRIVIAL ACTIVITIES

Except as otherwise prohibited or limited by this permit, the permittee is hereby authorized to operate any individual or combination of air emissions units that are considered inconsequential and are on the list in Appendix J. Any activity to which a State or federal applicable requirement applies is not trivial even if included on the trivial activities list. [OAC 252:100-8-2]

SECTION XVIII. OPERATIONAL FLEXIBILITY

A. A facility may implement any operating scenario allowed for in its Part 70 permit without the need for any permit revision or any notification to the DEQ (unless specified otherwise in the permit). When an operating scenario is changed, the permittee shall record in a log at the facility the scenario under which it is operating. [OAC 252:100-8-6 (a)(10) and (f)(1)]

B. The permittee may make changes within the facility that:

(1) result in no net emissions increases,
(2) are not modifications under any provision of Title I of the federal Clean Air Act, and
(3) do not cause any hourly or annual permitted emission rate of any existing emissions unit to be exceeded;

provided that the facility provides the EPA and the DEQ with written notification as required below in advance of the proposed changes, which shall be a minimum of 7 days, or 24 hours for emergencies as defined in OAC 252:100-8-6 (e). The permittee, the DEQ, and the EPA shall attach each such notice to their copy of the permit. For each such change, the written notification required above shall include a brief description of the change within the permitted facility, the date on which the change will occur, any change in emissions, and any permit term or condition that is no longer applicable as a result of the change. The permit shield provided by this permit does not apply to any change made pursuant to this subsection.[OAC 252:100-8-6 (f)(2)]

SECTION XIX. OTHER APPLICABLE & STATE-ONLY REQUIREMENTS

A. The following applicable requirements and state-only requirements apply to the facility unless elsewhere covered by a more restrictive requirement:

(1) No person shall cause or permit the discharge of emissions such that National Ambient Air Quality Standards (NAAQS) are exceeded on land outside the permitted facility. [OAC 252:100-3]
(2) Open burning of refuse and other combustible material is prohibited except as authorized in the specific examples and under the conditions listed in the Open Burning Subchapter. [OAC 252:100-13]
(3) No particulate emissions from any fuel-burning equipment with a rated heat input of 10 MMBTUH or less shall exceed 0.6 lb/MMBTU. [OAC 252:100-19]
(4) For all emissions units not subject to an opacity limit promulgated under 40 CFR, Part 60, NSPS, no discharge of greater than 20% opacity is allowed except for short-term occurrences which consist of not more than one six-minute period in any consecutive

60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity. [OAC 252:100-25]

(5) No visible fugitive dust emissions shall be discharged beyond the property line on which the emissions originate in such a manner as to damage or to interfere with the use of adjacent properties, or cause air quality standards to be exceeded, or interfere with the maintenance of air quality standards. [OAC 252:100-29]

(6) No sulfur oxide emissions from new gas-fired fuel-burning equipment shall exceed 0.2 lb/MMBTU. No existing source shall exceed the listed ambient air standards for sulfur dioxide. [OAC 252:100-31]

(7) Volatile Organic Compound (VOC) storage tanks built after December 24, 1974, and with a capacity of 400 gallons or more storing a liquid with a vapor pressure of 1.5 psia or greater under actual conditions shall be equipped with a permanent submerged fill pipe or with a vapor-recovery system. [OAC 252:100-37-15(b)]

(8) All fuel-burning equipment shall at all times be properly operated and maintained in a manner that will minimize emissions of VOCs. [OAC 252:100-37-36]

(9) Except as otherwise provided, no person shall cause or permit the emissions of any toxic air contaminant in such concentration as to cause or to contribute to a violation of the MAAC. **(State only)** [OAC 252:100-41]

SECTION XX. STRATOSPHERIC OZONE PROTECTION

A. The permittee shall comply with the following standards for production and consumption of ozone-depleting substances. [40 CFR 82, Subpart A]

(1) Persons producing, importing, or placing an order for production or importation of certain class I and class II substances, HCFC-22, or HCFC-141b shall be subject to the requirements of §82.4.

(2) Producers, importers, exporters, purchasers, and persons who transform or destroy certain class I and class II substances, HCFC-22, or HCFC-141b are subject to the recordkeeping requirements at §82.13.

(3) Class I substances (listed at Appendix A to Subpart A) include certain CFCs, Halons, HBFCs, carbon tetrachloride, trichloroethane (methyl chloroform), and bromomethane (Methyl Bromide). Class II substances (listed at Appendix B to Subpart A) include HCFCs.

B. If the permittee performs a service on motor (fleet) vehicles when this service involves an ozone-depleting substance refrigerant (or regulated substitute substance) in the motor vehicle air conditioner (MVAC), the permittee is subject to all applicable requirements. Note: The term “motor vehicle” as used in Subpart B does not include a vehicle in which final assembly of the vehicle has not been completed. The term “MVAC” as used in Subpart B does not include the air-tight sealed refrigeration system used as refrigerated cargo, or the system used on passenger buses using HCFC-22 refrigerant. [40 CFR 82, Subpart B]

C. The permittee shall comply with the following standards for recycling and emissions reduction except as provided for MVACs in Subpart B. [40 CFR 82, Subpart F]

(1) Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to § 82.156.
(2) Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to § 82.158.
(3) Persons performing maintenance, service, repair, or disposal of appliances must be certified by an approved technician certification program pursuant to § 82.161.
(4) Persons disposing of small appliances, MVACs, and MVAC-like appliances must comply with record-keeping requirements pursuant to § 82.166.
(5) Persons owning commercial or industrial process refrigeration equipment must comply with leak repair requirements pursuant to § 82.158.
(6) Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep records of refrigerant purchased and added to such appliances pursuant to § 82.166.

SECTION XXI. TITLE V APPROVAL LANGUAGE

A. DEQ wishes to reduce the time and work associated with permit review and, wherever it is not inconsistent with Federal requirements, to provide for incorporation of requirements established through construction permitting into the Sources' Title V permit without causing redundant review. Requirements from construction permits may be incorporated into the Title V permit through the administrative amendment process set forth in Oklahoma Administrative Code 252:100-8-7.2(a) only if the following procedures are followed:

(1) The construction permit goes out for a 30-day public notice and comment using the procedures set forth in 40 Code of Federal Regulations (CFR) § 70.7 (h)(1). This public notice shall include notice to the public that this permit is subject to Environmental Protection Agency (EPA) review, EPA objection, and petition to EPA, as provided by 40 CFR § 70.8; that the requirements of the construction permit will be incorporated into the Title V permit through the administrative amendment process; that the public will not receive another opportunity to provide comments when the requirements are incorporated into the Title V permit; and that EPA review, EPA objection, and petitions to EPA will not be available to the public when requirements from the construction permit are incorporated into the Title V permit.
(2) A copy of the construction permit application is sent to EPA, as provided by 40 CFR § 70.8(a)(1).
(3) A copy of the draft construction permit is sent to any affected State, as provided by 40 CFR § 70.8(b).
(4) A copy of the proposed construction permit is sent to EPA for a 45-day review period as provided by 40 CFR § 70.8(a) and (c).
(5) The DEQ complies with 40 CFR § 70.8 (c) upon the written receipt within the 45-day comment period of any EPA objection to the construction permit. The DEQ shall not issue the permit until EPA's objections are resolved to the satisfaction of EPA.

(6) The DEQ complies with 40 CFR § 70.8 (d).
(7) A copy of the final construction permit is sent to EPA as provided by 40 CFR § 70.8 (a).
(8) The DEQ shall not issue the proposed construction permit until any affected State and EPA have had an opportunity to review the proposed permit, as provided by these permit conditions.
(9) Any requirements of the construction permit may be reopened for cause after incorporation into the Title V permit by the administrative amendment process, by DEQ as provided in OAC 252:100-8-7.3 (a), (b), and (c), and by EPA as provided in 40 CFR § 70.7 (f) and (g).
(10) The DEQ shall not issue the administrative permit amendment if performance tests fail to demonstrate that the source is operating in substantial compliance with all permit requirements.

B. To the extent that these conditions are not followed, the Title V permit must go through the Title V review process.

SECTION XXII. CREDIBLE EVIDENCE

For the purpose of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any provision of the Oklahoma implementation plan, nothing shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

[OAC 252:100-43-6]

Valero Energy Corporation
TPI Petroleum, Inc.
Attn: Mr. John Shriver, P.E.
Environmental Manager
Post Office Box 188
Ardmore, OK 74302

Re: Construction Permit No. **98-172-C (M-17) (PSD)**
Valero Ardmore Refinery - 200 Long Ton per Day (LTPD) Sulfur Recovery Unit (SRU), 200 LTPD Tail Gas treating Unit (TGTU) and Amine Recovery Unit (ARU), and 100 Thousand Barrel per Day (MBPD) Crude Processing Rate Increase
Ardmore, Carter County

Dear Mr. Shriver:

Enclosed is the permit authorizing construction/modification of the referenced facility. Please note that this permit is issued subject to the certain standards and specific conditions, which are attached. These conditions must be carefully followed since they define the limits of the permit and will be confirmed by periodic inspections.

Thank you for your cooperation. If you have any questions, please refer to the permit number above and contact me at eric.milligan@deq.state.ok.us or at (405) 702-4217.

Sincerely,

Eric L. Milligan, P.E.
Engineering Section
AIR QUALITY DIVISION

enclosures

Copy: Ardmore DEQ Office (Carter County)

PART 70 PERMIT

AIR QUALITY DIVISION
STATE OF OKLAHOMA
DEPARTMENT OF ENVIRONMENTAL QUALITY
707 NORTH ROBINSON, SUITE 4100
P.O. BOX 1677
OKLAHOMA CITY, OKLAHOMA 73101-1677

Issuance Date: ______________________ **Permit Number:** **98-172-C (M-17) (PSD)**

Valero Energy Corporation, TPI Petroleum, Inc.,

having complied with the requirements of the law, is hereby granted permission to construct/modify the Valero Ardmore Refinery, located at in Section 16, T4N, R2E, in Carter County, Oklahoma, in accordance with this permit, subject to the following conditions, attached:

[X] Standard Conditions dated October 15, 2003

[X] Specific Conditions

In the absence of construction commencement, this permit shall expire 18 months from the issuance date, except as authorized under Section VIII of the Standard Conditions.

____ **Division Director, Air Quality Division**